# Center for Advanced Computation

UNIVERSITY OF ILLINOIS AT URBANA-CHAMPAIGN
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THE COAL FUTURE: ECONOMIC AND TECHNOLOGICAL ANALYSIS OF INITIATIVES AND INNOVATIONS TO SECURE FUEL SUPPLY INDEPENDENCE

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Michael Rieber
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James Stukel

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Final Report

# The Coal Future: Economic and Technological Analysis of Initiatives and Innovations to Secure Fuel Supply Independence

by

Michael Rieber
Center for Advanced Computation
University of Illinois at Urbana-Champaign

and

Shao Lee Soo
James Stukel
College of Engineering
University of Illinois at Urbana-Champaign

Advisor
Jack Simon, Chief
Illinois State Geological Survey

Center for Advanced Computation
University of Illinois at Urbana-Champaign
Urbana, Illinois 61801

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# SECTION I: INTRODUCTION

PROBLEMS

The use of coal has been declining relative to other fuels in almost every area of fuel consumption. Part of the problem is transportation, part of the problem is air pollution control, and part of the problem is that coal in its natural form is clearly the least flexible of all fossil fuels. Because it is solid and contains substantial amounts of waste, coal involves greater difficulty at every stage. It is more difficult to extract, transport, and handle in consumption than either oil or gas. Furthermore, after combustion, an ash and sulfur residues remain that create disposal problems. As a result, coal is used in its natural form only when it is significantly cheaper than other fuels. Moreover, in its natural form the economies of scale in coal handling are such that only large users find that they can cheaply overcome the cost disadvantages. This explains the concentration of coal use among large consumers of fuel.

The principal obstacles to the use of coal involve transport costs and sulfur content. Transport costs are high with respect to the price of coal at the pit head. Reductions in transport costs arising from changes in the mode of transport result in a lower supply price for coal at the consumption point. With respect to sulfur content, given the desire to avoid the degradation of the environment, air pollution control regulations may be viewed as a mechanism which increases the supply price of coal to the consumer. To the extent that desulfurization does not take place, air pollution control regulations may be viewed as limiting the supply of coal to naturally occurring low sulfur coal sources. Therefore, all desulfurization activity can be considered a means

by which supply is increased. To the extent that desulfurization costs are reduced, this too may be viewed as a reduction in the supply price of coal to the consumer.

While desulfurization is usually thought of in terms of stack gas scrubbing alone, it also takes place when coal is gasified or liquefied. These methods bear not only on the supply of coal, but upon substitute fuels such as natural gas and fuel oil. Coal may be gasified into a high Btu gas, substitutable for pipelined natural gas, a medium Btu gas, substitutable for natural gas or oil, or to a low Btu gas which must be used in the proximity of the gasification plant and is limited primarily to electric power generation. It is substitutable for coal, natural gas and nuclear power. Finally, sulfur may be removed during the combustion process (fluidized bed, molten iron bath, etc.) if these laboratory scale processes ultimately prove successful.

In all of these processes, sulfur is removed and the product can meet EPA standards. It should also be noted that an innovative transport method, such as the high pressure pneumatic pipelining of coal, may involve not only transportation, but the densification and partial desulfurization of coal as well because, prior to pipelining, the coal can be crushed, cleaned and much of the ash and at least some of the pyritic sulfur removed. Consequently, some high sulfur coal may be able to meet air pollution control standards without further processing while for the remainder, desulfurization and ash control after combustion may be somewhat easier.

If transport costs and desulfurization problems are overcome then, in addition to supplementing and/or reducing the need for nuclear power generation, the use of coal for electric power and process heat would free petroleum and natural gas for application to home heating, light industry

and commerce, and transport (i.e., an effective increase in the supply of those fuels) where fuel substitution is low. If coal powered pneumatic or slurry pipelines are economically feasible, diesel fuel oil, currently used for coal transport, would be available for alternate uses. Additionally, coal fired power generation could be used in place of stationary diesel turbines, for pipeline stations, and the electrification of much of the rail network, thus saving additional diesel fuel oil. Cheaper forms of transport would also aid in the optimal siting of power plants, gasification plants and industrial users. The mere fact that a synthetic fuel industry exists provides a technological counter-measure to the oil weapon.

## A. Research Objectives

The basic objective is the identification of those areas where the expected relative payoff of increased government expenditures on research and development, taxes and subsidies, and other incentives designed to expedite the increase in economically recoverable domestic reserves of coal, the commercial upgrading of coal to superior end use products, and innovations leading to lower cost coal transportation is highest.

Government policies operate in the manner of offsets to cost but may be limited to specific categories of cost. Therefore, they may influence the supply of coal offered or available at a given price, or they may shorten the time horizon of the development of new supplies of coal or coal based energy products, or they may promote additional supplies from existing sources. In addition to the usual research and development subsidies, direct government expenditures can be used to underwrite capital costs for new and expanded plants,

support exploration and recovery, and underwrite safety, siting and fuel transportation costs. Similar results can be obtained by tax policy with respect to industry development of new resources and processes. Other policy parameters include leasing and land use policies, patent law, price and profit guarantees, tariffs and embargo policies, cost sharing and the use of government facilities. Profitability and induced changes in profitability are the bases for the alteration.

The shortening of the expected time horizon to commercial output of currently unusable or submarginal coal sources and processes, due to shifts in government parameters, is desirable. Clearly, if domestic output will increase significantly and rapidly, spurred only by increased energy prices, government support has a low payoff. This implies that productive units are of minimum efficient size. For comparable increments of government expenditure or support, both direct and indirect, the relative time horizon for additional output units and the size of those units are important data for policy evaluation.

The policy considerations in this study involve the minimization of both costs and physical resource waste and the maximization of our major domestic fuel supply. For a given output of energy, money is saved by concentrating government expenditures in high payoff areas. In the light of the reported future energy shortage, government support has been proposed across a broad spectrum of fuels and processes. In terms of coal, clean coal production and reserves are to be increased by accelerating the search for and production of naturally occurring low sulfur sources. Additionally, high sulfur coal is to be upgraded and its usefulness expanded by cleaning, stack gas scrubbing, gasification to high, medium

and low Btu synthetic natural gas, solvent extraction and liquefication to syncrude or fuel oil.

A study of government policy options is of value because these represent different routes and government or social cost incurred in the pursuit of a given objective. While it is possible that some forms of government activity preclude, discourage or offset private activity (e.g., research and development) it has not yet been shown that private firms are either interested or financially capable of undertaking extensive developmental research in some areas, or that they have a sufficient community of interest for cooperation, or that they will spend money to offset social costs. Neither the coal industry nor the railroads appear to be financially strong enough to undertake development work. The utilities are understandably not interested in processes that add primarily to costs but not revenues. A number of them have, however, spent millions of their own money on government supported research and demonstration projects.

## B. Research Program

This study is divided into five interrelated areas:

1. Estimation and validation of nuclear power fuel cycle estimates.
2. Re-evaluation of low sulfur coal estimates and analysis of coal reserve/resouce estimation.
3. Estimation of comparative costs of coal transportation including unit trains, slurry pipelines and high pressure pneumatic pipelines.
4. Comparative cost and feasibility estimates of coal desulfurization by stack gas scrubbing and low Btu gasification.

5. Analysis of coal gasification to a medium Btu coal gas (300-350 Btu/scf).

The analyses include both technology assessment and cost estimation.

The remaining bastion of coal utilization is the electric utilities. If coal is to have a future under current conditions it must meet the ceiling price set by electric power generation based on nuclear fuels. Given the wide range of nuclear power cost and availability estimates, an evaluation and analysis of nuclear power fuel cycle costs was completed to determine the price ceiling for coal at the point of consumption and the probable future market.

Based on existing air pollution control regulations coal must be divided into high and low sulfur categories. Furthermore, the regulations are written with respect to consumption rather than sulfur content as produced. In the absence of air pollution control processes, low sulfur coal reserves/resources and production are of primary importance. Because coal reserve and resource estimates by sulfur category are made on a production (mined) basis, they were re-evaluated on a consumption basis. This provides the correct estimate of low sulfur coal for policy purposes.

In meeting both the price ceiling set by nuclear power and the forecasts of future coal usage, a major burden is placed on coal transportation. Therefore three alternate modes were compared. These include unit trains, slurry pipelines and pneumatic pipelines. The primary focus was on capacity, feasibility and cost reduction potential. Unit trains were the standard for comparison.

In the absence of adequate reserves of naturally occurring low sulfur coal, the time horizon for the development of

adequate production capacity, and the cost and availability of high sulfur coal, two competing methods of coal desulfurization were compared. These were stack gas desulfurization and the production of low Btu coal gas for utility use. While the use of available low sulfur coal is an immediate solution to some energy-environmental problems, the coal future depends on the efficient use of high sulfur coal.

In the 1950's, coal was a major energy source in almost all segments of the market. If its former markets of industrial, large commercial and governmental complexes can be re-established, significant amounts of natural gas and petroleum products can be displaced. Medium Btu coal gasification offers one method by which this may be accomplished. The study outlines the process and provides an economic evaluation of the possible results.

## C. Major Findings and Recommendations

### 1. Nuclear Power

The economic superiority of fissile or fossil electric power generation has not yet been demonstrated. Both sides have proponents and new contracts are being let by utilities for both steam systems. Each provides a ceiling price or comparative standard for the other. Because nuclear power capital costs are signficantly higher than the capital costs for an equal electrical output if coal fired, nuclear power plants, if they are to be economically competitive, must have lower fuel cycle costs over the lifetime of the plant. Specifically, the present discounted value of the fuel cost saving due to electric power generation using nuclear fuel must offset the difference between the respective capital costs of

nuclear and coal fired facilities. Therefore, the study of the nuclear fuel cycle cost is of importance.

The cost of nuclear power (Section II) sets the ceiling for the use of coal, including desulfurization and waste disposal as needed, by electric utilities. AEC estimates for 1980 are slightly over 15 mills/kwhe. However, using AEC data and a methodology derived from AEC publications, it is found that the costs to a utility in 1980 will be at least 22 mills/kwhe. At the bus-bar the price is likely to be over 32 mills/kwhe.

Additional findings indicate that AEC projections of nuclear capacity for the period 1980-1985 are significantly overstated. Coal will necessarily fill the gap unless increased dependence on foreign oil or a major recession are postulated.

Other conclusions developed are: 1) The load factor for nuclear plants is considerably below that postulated by the AEC. This leads to a further derating of future power availability estimates and increases in nuclear power costs. 2) There are indications that nuclear power costs include some subsidies and therefore are underestimated.

The present study includes a complete methodology for the estimation of fuel cycle costs from the mine and mill through the reactor to storage or recycle. Although the AEC in its nuclear cost analysis has not published a consistent accounting system, the methodology is derived from AEC documents and a study made by the NUS Corporation.

It is estimated that approximately 14 percent of the annual energy output of a reactor is required to mine, mill, convert, enrich, process, ship and manage the wastes required for fueling a reactor. Additionally, the energy cost of constructing a reactor is 9.55 trillion Btu, or about 2.79 bil-

lion kwh. Based on an input-output analysis of both direct and indirect energy costs of the fuel cycle and construction, it is possible to estimate the contribution of new nuclear power plants to Project Independence. Using extremely conservative assumptions concerning the number of new nuclear power plants from 1975-1985, i.e., 10 new plants in 1975, accelerating by one per year to 20 new plants started in 1985, the total net national energy debt by 1985 will be 96 billion kwhe. With respect to Project Independence a nuclear program may be an energy sink.

## 2. Coal Reserve/Resource Estimates

Section III deals primarily with the validation of our coal reserve/resource base. Of particular interest is low sulfur coal. Conventionally, the definition of low sulfur coal, on which traditional reserve and supply estimates are based, depends only on the weight of sulfur in a ton of coal. The Btu content of coal is not considered. However, coal purchases and $SO_2$ regulations are based on Btu content. A recalculation of reserve estimates of low sulfur coal, on a utility average Btu basis, reduces traditional U.S. low sulfur coal estimates by over 75 percent and western estimates by almost 85 percent.

When calculated on the standardized Btu basis, maximizing low sulfur coal production results in a supply shortage by 1985.

The data revisions are significant for both energy policy planning and air pollution control. Based on our estimates known recoverable reserves of $\leq$ 0.7 percent sulfur coal (on a user basis) could fall over 1 billion tons short of the maximum cumulative production in the period from 1970-

1985. To forestall this, a number of specific policy suggestions are made.

With respect to coal reserves and resources in general, it is found that we do not yet have, on a national basis, a sufficiently accurate schematic system for accurate assessment and classification of our reserve/resource position. This is true with respect, not only to the Bureau of Mines' data bank but also to the use and application of standard recovery factors for reserves which are inconsistent with reserve estimation because they are not sufficiently discriminatory among coals and among habitats.

In order to estimate the reliability of coal reserve estimates, analyses were made of Illinois, Wyoming and the Bureau of Mines schematics. Illinois is a developed coal state, Wyoming is a new coal province. With respect to total coal reserves/resources, analysis indicates that while Illinois estimates are probably the best extant, they are likely to be conservative. Western coal reserve/resource estimates, exemplified by Wyoming, range from good in some limited areas to crude approximations. Their use for predictive policy purposes is limited. The Bureau of Mines' data bank, while extremely helpful for current conditions, employs a methodology that results in a crude overall estimate of reserves. The result is a restricted usefulness for policy.

It is suggested that there is a need, through the Bureau of Mines, for the development of a systematic methodology for obtaining estimates of economically recoverable reserves from physical reserves and physical reserves from identified resources. This means close attention to prices and the evaluation of relevant state-of-the-art technologies given the geophysical characteristics of the seam and habitat.

This may require much more mine disclosure in the national interest. Additionally, a significant amount of development drilling should be undertaken in order, not only to firm up the estimates of the resources lying behind the reserves but, to estimate coal qualities as well.

Mine productivity which, before the health and safety regulations, was increasing at a decreasing rate, is now decreasing but is rapidly leveling off. Longwall mining appears to be the least affected. Increases in productivity appear to be most closely associated with better methods of haulage from the mine face and to the surface.

## 3. Coal Transportation

A lack of handling flexibility is one of the two major drawbacks in the use of coal. It leads to relatively low productivity in mining and high cost in distribution. The emphasis in Section IV is on the costs of distribution rather than on the prices charged. The latter often reflects the lack of competition in coal haulage and therefore may include large elements of monopoly profit or economic rent. Additionally, for policy purposes, it is the cost comparisons that are important with respect to the efficient allocation of scarce resources. The analysis includes unit trains, coal slurry pipelines and high pressure pneumatic pipelines. This last has been included even though it has not yet reached the commercial stage of the first two because, given the enormous haulage requirements forecast for the near future, reasonable alternatives in the developmental stage are important.

Unit trains are used as the standard for comparison. Slurry pipelines and unit trains are directly competitive alternatives. A long distance pneumatic pipeline may be competitive with either. A short distance pneumatic pipeline

could be used as the basis of a gathering or distribution system for rail or barge shipments. It is not directly compatible for use with a slurry pipeline because of the wetness of the coal particles coming from the latter.

Our findings confirm those made elsewhere that when new railroad is to be built (even if only 40 percent of the total distance) a slurry pipeline may have a cost advantage of as much as 2:1. However, water requirements and the results of possible line breaks or power loss, which require dumping the slurry, are still unsolved environmental impact problems.

Where roadbed is already available, even if the most elaborate upgrading is required to sustain a minimum loaded train speed of 50 mph, the resultant transportation cost is only one-half that of a new slurry pipeline. This result, together with the availability of the rail for other types of shipment, rules out replacing existing railroad by slurry pipelines. Where railroad is non-existent and for long distances, a pneumatic pipeline will, in the future, become competitive with a slurry pipeline. Therefore, abandoning railroads in favor of slurry pipelines, such as the one proposed for shipment from Wyoming to Arkansas, would be a policy error. Our recommendation includes identification of coal shipping railroads for upgrading and federal expenditures to study the alternative indirect economic and social impacts.

The cost analyses are based on a unit train data base which has been developed for comparison with other coal transport options. Pipeline costs have been based upon existing slurry pipelines and engineering studies.

The operation of unit trains suffers from the lack of a back haul to the mining area. It is here that the greatest opportunity for cost reduction exists. Even a marginal

system, such as sewage for fertilizer and ash from coal or land reclamation could make the return trip productive. The rail operation may be further facilitated by the use of pneumatic pipelines. While high pressure long distance pneumatic systems remain to be developed, short distance pneumatic pipelines of 1 to 20 miles can be furnished with current technology. These lines carrying up to 2,400 tons of coal (2 in. by 0 in.) per day can be used in place of abandoned rail lines in gathering to or distributing from unit train terminals.

The costs of slurry pipelines are compared to unit train costs of operation to the same destination. Slurry pipelines cost one-half as much as new railroad but are double the cost of the best upgrading of existing railroad. The large coal hold up in a slurry pipeline (855,000 tons of coal in the proposed Wyoming to Arkansas line) poses an unsolvable problem in case of power outage. It also leads to significant storage problems if the receiving facility is temporarily not operating.

Based on current technology, pneumatic pipelines appear most competitive with the ~~trucks and belt~~ conveyors for the gathering to and distribution from a rail terminal. Given the trend toward the abandonment of branch lines, this is desirable.

It appears that the most immediate applications of a pneumatic pipeline is that of a transport system for coal in conjunction with the use of the right-of-way of a railroad system. Supplying a large gasification facility from a railroad terminal by pneumatic pipeline is desirable because the coal size is correct for most gasification processes. Because of the speed of shipment in a pneumatic pipeline, storage is needed only at one end. This is significant

because of the volume required for 60-day storage for a plant using 25,000 tons of coal per day. A slurry pipeline can also be supplied from a railroad. However, the requirement with respect to coal size for the slurry makes the dried coal unsuitable for feeding a gasification system.

4. $SO_2$ Removal

Stack gas desulfurization and low Btu gasification (Section V) can be viewed as competing forms for the utilization of high sulfur coal in an environmentally acceptable manner, given the potential shortfall of low sulfur coal.

In general it is found that the use of stack gas desulfurization is a dead end technology. It is suitable primarily for older and smaller coal fired plants and those where water restrictions preclude low Btu coal gasification. Low Btu gasification, especially with combined cycle operation, is an expanding technology and should be supported.

With respect to stack gas desulfurization, there are two major processes. Throw-away, which leads to major pollution and disposal problems and regenerative processes. If using a 3 percent sulfur coal, 75 percent removal efficiency is needed to meet most air pollution control standards. An 85 percent removal efficiency will meet most state standards. Almost all of the stack gas desulfurization processes can meet the requirements. The utility industry is almost totally committed to throw-away processes. The size of the disposal problem with respect to the throw-away processes can be seen with respect to a 550 megawatt coal plant which produces over 2,000 tons of sludge per day. Aside from the volume, there may also be leaching problems. It is suggested, therefore, that to the extent stack gas scrubbing is promoted,

it should be the regenerative process which produces sulfur or concentrated acid as the waste product. However, this is more costly and has a depressing effect on the sulfur market.

Assuming a 3.5 percent sulfur coal, the space requirements for desulfurization units are approximately 24 square feet per megawatt. This excludes the holding tanks for the sludge. For a 550 megawatt plant, approximately 13,200 square feet are required. A significant number of plants requiring retrofit do not have the available space.

Given the time required for installation, on the average, a maximum of 20 percent of the nation's electrical generating capacity can be retrofitted in any one year. Therefore, a stack gas scrubbing program is not likely to be able to meet current $SO_2$ control dating requirements without significant power shortages.

The power requirements for a stack gas scrubber amount to between 2 and 7 percent of the power output of the boilers. This amounts to a drain of total available electrical capacity in the interests of air pollution control.

Coal gasification plants may be generally divided into high and low pressure systems for the production of low Btu gas. High pressure low Btu gasification can be utilized in a more advanced power design, that of a combined cycle power plant. The combination of the electricity generated from both the gas turbine and the steam turbine gives rise to an increased overall plant efficiency. The thermal efficiency for the gas production alone is 70 to 80 percent. The electric power generation efficiencies for the boilers is in the range of 38 to 40 percent. However, with a combined cycle, this electric power generation efficiency can rise to 47 percent. Therefore, if low Btu gas is used in a combined cycle operation, the result is environmentally clean coal use as

well as reduced overall coal use in the power plant. It is in this area that federal emphasis should be placed. Without the use of a combined cycle operation, the burning of low Btu gas, like that of stack gas scrubbing, involves an energy loss in the effort to remove $SO_2$.

Low Btu gasification is probably limited to large installations. A number of specific problems inherent in low Btu gasification in general and the Lurgi process (the only current high pressure process) in particular are noted in the discussion. Other processes are in the developmental stage. The waste disposal problem for coal gasification plants includes typical fly ash and sulfur. The space requirements are non-trivial but while the plant must be near, it need not be at, the power site. Water requirements are a very significant problem.

Given the wide range of estimates of capital, operating and maintenance costs, as well as the significantly different bases on which these costs are estimated. Additional work should be undertaken for validation. This is necessary to reconcile the various counter claims before establishing firm policy guidelines.

## 5. Medium Btu Coal Gasification

Section VI discusses medium Btu coal gasification. Virtually all low Btu coal gasification processes can be adapted to produce a medium Btu gas of 300-350 Btu/scf. The advantage of this quality gas is its siting flexibility and its adaptability to the existing boiler sizes and characteristics used by industrial, commercial and governmental complexes. Additionally, because the generation can be relatively small-scale and can produce both electricity and process steam, both electric utilities and consumers can be freed of their

mutual interdependence. Given the projected demand for electricity and the problems foreseen in supplying this demand solely by the expansion of the utility industry, consumer generation of their own electricity, in whole or in part, along with process heat or steam, may be an important national priority.

The particular system discussed here has been designed for relatively small-scale operations (industrial/commercial size) and does not require oxygen in the process (making it relatively safe). The conclusions, however, are believed to be valid for medium Btu coal gasification in general. It is one method to re-acquire previously lost coal markets.

## SECTION II: NUCLEAR POWER FUEL CYCLE COSTS

### A. Introduction

The base case for a study of the coal future must include an evaluation of anticipated world oil and nuclear power prices on both the value of domestic reserves of coal (i.e., the addition to the stock of economically recoverable reserves due soley to increased sale price) and the new commercial position of coal upgrading processes. Increases in import and nuclear power prices raise the value of previously uneconomic reserves. They also diminish the percent of the total supply price due to fixed processing costs. Thus, in addition to providing the data against which to evaluate government expenditures, such studies help to measure the effect of world and domestic prices on the development of additional commercial reserves of coal and the commercial availability of new coal based energy sources.

The cost of nuclear power sets the ceiling for the use of coal, including desulfurization and waste disposal as needed, by electric utilities. AEC estimates for 1980 have been slightly over 15 mills/kwhe of electricity. However, using AEC data and a methodology derived from AEC publications, it is found that the cost to the utility in 1980 will be at least 22 mills/kwhe of electricity. At the bus-bar the price is likely to be over 32 mills/kwhe of electricity. Additional findings indicate that AEC projections of nuclear capacity for the period 1980-1985 are significantly overstated. Coal will necessarily fill the gap unless increased dependence on foreign oil or a major recession are postulated. Other conclusions developed are: (1) the load factor for nuclear plants

is considerably below that postulated by the AEC. This leads to a derating of future power availability estimates and increases in nuclear power costs. (2) There are indications that nuclear power costs include some subsidies and therefore are understated.

The economic superiority of fissile or fossil electric power generation has not yet been demonstrated. Both sides have proponents and new contracts are being let by utilities for both steam systems. Each provides a ceiling price or comparative standard for the other. Because nuclear power capital costs are significantly higher than the capital costs for an equal electrical output if coal fired, nuclear power plants, if they are to be economically competitive, must have lower fuel cycle costs over the lifetime of the plant. Specifically, the present discounted value of the fuel cost savings due to electric power generation using nuclear fuel must offset the difference between the respective capital costs of nuclear and coal fired facilities. Therefore, a study of the cost of nuclear power was made in order to provide a standard for coal.

## B. Summary and Conclusions

The study indicates that the AEC fuel cycle cost estimates are too low. Furthermore, all cost elements are not included. Finally, if the costs are calculated at the bus-bar rather than as the cost to the utility, the increase in the estimated cost is substantial.

Nuclear supply forecasts are relevant to Project Independence but an analysis of the delays and downward revisions in the estimates point to restricted construction programs and increasing finance costs due to delay. Table I-1* presents a comparison of the supply projections made in this

study with those made by others. With the exception of the projected maximum for 1985, all of the estimates in this study are lower than those made by any other agency. It would appear that current events may make even these relatively pessimistic estimates appear overly optimistic. This has been recognized by the AEC which reduced its estimate for 1980, first to 125,000 megawatts and later to 102,000 megawatts of electricity.

Because nuclear power plants cost more per kilowatt to build than fossil plants, to be economic the fuel cycle costs must be low enough to offset the difference. The amount that must be offset is inversely proportional to the load factor and directly proportional to the capital cost. Furthermore, because the ratio of fuel cycle to total cost is higher for fossil than it is for nuclear plants, the cost advantage of nuclear over fossil fuel plants is directly proportional to the assumed load factor. In its cost comparisons the AEC has almost consistently used an 80 percent load factor for its nuclear plants. This study shows that the historical load factor has been about 65 percent or less. In a recent forecast the AEC, Office of Planning and Analysis, reduced its operating capacity assumption to 75 percent. However, even 75 percent is considerably higher than the historic average. Therefore, in examining Table I-1 it should be remembered that the estimates should be reduced to 60 or 70 percent of those tabulated in order to arrive at the amount of electricity that can be expected to be available to the consumer.

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* Table numbers are consistent with those found in Michael Rieber and Ronald Halcrow, Nuclear Power to 1985: Possible versus Optimistic Estimates, Center for Advanced Computation, University of Illinois at Urbana-Champaign, CAC Document No. 137P, November 1974.

TABLE I-1

Comparison of Nuclear Capacity Forecasts
(000 MWe)

| | 1970 | 1975 | 1980 | 1985 |
|---|---|---|---|---|
| AEC Wash 1139 (1972) | 5.9 | 54.2 | 132.0 | 280 |
| Electrical World | 6.2 | 56.5 | 128.1 | -- |
| Department of the Interior | -- | 50.0 | 120.0 | 215 |
| FPC (National Power Survey) | 6.0 | -- | 147.0 | -- |
| NPC (Case III) | -- | 64.0 | 150.0 | 300 |
| Atomic Industrial Forum | -- | 59.0 | 146.0 | 302 |
| This Study (projected)(1) | -- | 47.8 | 94.6 | -- |
| (projected maximum)(2) | -- | 47.8 | 119.1 | 250.0 |

Sources: U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 1 Sess., Phase I, July 31 and August 1, 1973, p. 48.

(1) Table II-1.

(2) Table II-2.

The present study includes a complete methodology for the estimation of fuel cycle costs from the mine and mill through the reactor to storage or recycle. Although the AEC in its nuclear cost analysis has not published a consistent accounting system, the methodology is derived from AEC documents and a study made by the NUS Corporation. The procedure is sufficiently detailed to allow anyone with better numbers to make their own estimates. The fuel cycle costs developed here are greater than those reported by the AEC by at least a factor of two. Major differences arise due to differences in cost escalation, mining and milling, and enrichment costs.

While capital and other non-fuel costs are discussed in this study, given the lack of consistency, inadequate reporting and multiple bases used, most of the work is qualitative. Even when direct capital costs are given, escalation has been at less than market indicated rates. The cost of capital has been consistently low and the load factor used to convert to mills/kwh of electricity has been higher than either current or historic levels. As a result, capital costs in mills/kwhe reported by the AEC and some companies seeking licenses are too low.

In 1973, the Atomic Energy Commission projected 1981 power generation costs at 15.20 mills/kwhe for a 1,000 MWe light water nuclear reactor. This was the sum of 11.70 mills/kwhe for capital, 2.50 mills/kwhe for fuel, and 1.00 mills/kwhe for operation and maintenance. Based on these 1973 estimates, and the 5 percent escalation rate suggested by the AEC, 1980 costs would be 11.57, 2.50, and 0.95 mills/kwhe, respectively: a total of 15.02 mills/kwhe. For comparison, Table I-2 summarizes the nuclear power generation cost developed in this study. The 1980 costs are projected at 22.11 mills/kwhe, a difference of more than 7 mills/kwhe over the AEC estimate.

Given the capital costs, the influence of the load factor is of particular relevance to a cost comparison between nu-

TABLE I-2

Projected 1980 Generation Costs

for an Average 1000 MWe

Light Water Nuclear Power Plant

(mills/Kwhe)

| Cost Component | |
|---|---|
| Capital | 16.02 |
| Fuel | 4.97 |
| Operation and Maintenance (O and M) | 1.12 |
| Total Generation Costs | 22.11 |

Sources: Tables I-3, III-2, and Atomic Energy Commission, The Nuclear Industry 1973, WASH 1174-73, p. 15.

Note: The AEC estimated 1973 O and M costs of 0.70 mills/Kwhe, escalating at 7 percent annually results in a 1980 cost of 1.12 mills/Kwhe.

clear and fossil fuels. Based on AEC estimates, total 1980 capital costs for a 1,000 MWe nuclear plant are $608 million or 16.02, 14.87, 13.88, and 13.01 mills/kwhe for load factors of 65, 70, 75 and 80 percent, respectively. These costs include interest, added as an indirect cost, of 7 percent annually, and escalation, due to inflation, compounded at 7 percent annually.

Based on an analysis of nuclear power costs made by Arthur D. Little, Inc., it is possible to derive considerably higher nuclear power electric generation costs. For a 1,000 MWe nuclear power plant, Arthur D. Little estimates lead to a capital cost of $649 million. Based on a 65 percent availability factor and an annual capital cost rate of 15 percent, these costs equal 17.09 mills/kwhe. Assuming an annual fixed charge rate on capital of 24.04 percent, a capital cost of 26.89 mills/kwhe is derived. Assuming that fuel, operation and maintenance costs are those found in Table I-2, 1980 nuclear power electric generation costs could be 32.98 mills/kwhe.

## C. Major Findings

### 1. Forecasts

The nuclear forecast in this study is based on a five and one-half to six year construction period. For plants not yet under construction an eight year lead time has been assumed. This includes the period from the date of application for a construction permit to the expected date of commercial operation. For plants for which there is not even a reported date of filing for a construction permit, a ten year lead time from the date of order was assumed.

New plant completions are expected to continue at a level below 10,000 MWe/year until 1981. Subsequently, plants ordered in 1972 and 1973, are scheduled to begin operation. Installed generating capacity at the end of 1973, was approximately 24,000 MWe. This capacity level is expected to increase to 47,788 MWe by the end of 1975. Plant capacity in 1980 is estimated to be 94,562 MWe. The 1983 estimate was based on present nuclear plant orders and a five and one-half year completion allowance from the date construction is reported to begin. This resulted in an estimate of firm nuclear plant capacity of 173,854 MWe. By including those plants which were announced only by letters of intent or options, plus those plants for which no site or vendor was named, the estimate of installed generating capacity in 1983, was increased to 197,266 MWe.

Based on orders published in the journal of the Atomic Industrial Forum, Nuclear Industry, a maximum estimate of cumulative installed nuclear plant generating capacity was made. Table II-2 shows this maximum estimate, given the assumption that the trend of plant orders indicated in the past continues. The estimate assumes that installation rates are maintained near the 1980-1981 rates and are higher than the assumed 1982-1983 rates. Nuclear capacity levels in Table II-2 for 1975, 1980, and 1985 are 47,788 MWe, 119,111 MWe and 250,331 Mwe, respectively.

Both the AEC estimates and those presented in this paper may be overly optimistic. The recent rash of planned nuclear power plant delays and curtailments due to financing problems and utility re-evaluations of projected demand, postdate the AEC forecasts and have not been accounted for in any of the tables presented in this study.

TABLE II-2

Maximum Installed Nuclear Plant Generating Capacity: Cumulative
MW(e)

| | 1973 | 1974 | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PAD District I | 11980 | 17247 | 25269 | 29284 | 32254 | 37002 | 46094 | 56492 | 67562 | 73210 | 87360 | 97360 | 107360 |
| PAD District II | 9373 | 11573 | 12627 | 15802 | 18935 | 21185 | 26152 | 34334 | 43504 | 50404 | 59766 | 64766 | 69766 |
| PAD District III | 1718 | 3686 | 5664 | 6590 | 7450 | 8750 | 12445 | 16965 | 19165 | 24905 | 29355 | 34355 | 39355 |
| PAD District IV | 0 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 330 | 1000 |
| PAD District V | 795 | 1708 | 3898 | 5054 | 6154 | 6154 | 7294 | 10990 | 12230 | 12990 | 22850 | 27850 | 32850 |
| Total | 23866 | 34544 | 47788 | 57060 | 65123 | 73421 | 92315 | 119111 | 142791 | 161839 | 199661 | 224661 | 250331 |

Sources: Tables II-5 and II-6. For the 1984-1985 estimate, the extrapolation is based on data in Table II-5.

| | 1984 | 1985 |
|---|---|---|
| PAD District I | 10000 | 10000 |
| PAD District II | 5000 | 5000 |
| PAD District III | 5000 | 5000 |
| PAD District IV | - | 770 |
| PAD District V | 5000 | 5000 |
| Total | 25000 | 25770 |

If the (1972) AEC and (1973) AIF national estimates for 1985 of 280,000 and 365,000 MW(e), respectively, are to be met, yearly additions for 1984-1985 must be:

| | 1984 | 1984 |
|---|---|---|
| AEC | 40000 | 40000 |
| AIF | 82500 | 82500 |

## 2. Plant Availability

The amount of nuclear power available depends, not only on plant capacity, but upon plant availability as well. The latter has been the subject of some controversy. A summary of nuclear plant availability through August 1973, indicates an average plant factor (availability) of 60.9 percent from start-up through October 1972. Subsequently, quarterly ratings were made. These plant factors ranged from 66.3 to 72.9 percent.

In the future, as new plants are added at an increasing rate, the availability rating trend will be downward because initial start-up rates have been historically closer to 60 percent availability than to 80 percent availability. The new plants will weight the average more than the debugged older plants.

Because partial outages resulting from component failures were not included nor were temporary restrictions on plant capacities considered, plant availability factors are statistically biased upwards. It should also be noted that there is a difference between the plant availability factor and the plant capacity factor. The former is the percent of the total time in a given period that a plant or unit was producing electricity. The capacity factor is the percent of the total electrical energy actually produced by a plant or unit during a period compared to the energy it might have produced had it operated at the licensed designed power level for the entire period. Therefore, the capacity factor will be smaller than the plant availability factor.

## 3. Fuel Cycle Costs

An analysis of fuel cycle costs is necessary due to a wide variation among estimates made by the Atomic Energy Com-

TABLE II-8 (Cont.)

Weighted Plant Factors: Startup Through March 31, 1974

Totals

| Plant | Total (MWe (net) | - to 9/30/72 | 10/1 to 12/31/72 | 1/1 to 4/30/73 | 5/1 to 8/31/73 | 9/1 to 12/31/73 | 1/1 to 3/31/74 |
|---|---|---|---|---|---|---|---|
| Totals | | | | | | | |
| PAD District I | 11106 | .683 | .684 | .649 | .687 | .682 | .657 |
| PAD District II | 7473 | .516 | .715 | .661 | .814 | .736 | .633 |
| PAD District III | 1718 | | | | | | |
| PAD District IV | - | | | | | | |
| PAD District V | 795 | .594 | .930 | .960 | .521 | .41 | .76 |
| Total | 21092 | .609 | .682 | .663 | .729 | .697 | .649 |

Source: Atomic Industrial Forum, Nuclear Industry.
Nov.-Dec. 1972, p. 21
Feb. 1973, pp. 32-33
June 1973, pp. 22-23
Oct. 1973, pp. 24-25

mission, the National Petroleum Council and others. Calculations made by these organizations and others are based on different cost estimates or non-comparable assumptions. Furthermore, a simple and direct methodology is not presented with the cost estimates. The current study is an effort to put the methodology for calculating nuclear fuel cycle costs on a consistent and comprehensible basis. It is also an attempt to measure these costs under several different conditions. This study evaluates the fuel cycle costs that can be expected in the nuclear power industry in the 1980's.

Between exploration and burnup in a light water nuclear power plant, uranium must be mined, milled, converted, enriched, processed and fabricated. Once the enriched uranium is used in a nuclear plant, additional costs arise due to waste management or recycling of the spent fuel. Finally, fuel inventory charges must be accounted for. Together these costs make up the nuclear fuel cycle cost. Costs due to safeguarding the fuel and insurance liability, as well as decommissioning, are considered separately.

The projected fuel cycle costs, in 1980 dollars, for a typical light water nuclear power plant are given in Table III-2. These costs were derived by using a seven percent annual rate of inflation on the most likely component cost estimates. Table III-2 indicates an annual nuclear fuel cycle cost of $28,281,097 or 4.97 mills/kwhe for an average 1,000 MWe nuclear power plant. This average plant (the average of two pressurized water and one boiling water reactor) is expected to have a 65 percent load factor, a high core burnup rate, and an efficiency rating slightly above normal.

The model plant does not possess some standard characteristics that have been assumed by the AEC in the past. In estimating fuel cycle costs, the AEC has assumed a load factor of 80 percent, a lower core burnup rate than that in the model

**TABLE III-2**

1980 Fuel Cycle Costs for an
Average 1000 MWe Nuclear
Power Plant
(1980 Dollars)

| Cost Component | Cost/Unit | Quantity/Yr. | Cost/Yr. | mills/kwhe |
|---|---|---|---|---|
| a) Mining and Milling | $20/lb $U_3O_8$ | 270,930 lbs $U_3O_8$ | $5,418,600 | .95 |
| b) Conversion to $UF_6$ | $5/kg U | 104,192 kg U | $520,960 | .09 |
| c) Enrichment | $97/kg SWU | 102,745 SWU | $9,966,265 | 1.75 |
| d) Fuel Preparation and Fabrication | $112/kg U | 25,622 kg U | $2,869,664 | .50 |
| e) Spent Fuel Shipping | $8/kg U | 22,934 kg U | $183,472 | .03 |
| f) Reprocessing | $56/kg U | 22,934 kg U | $1,284,304 | .23 |
| g) Reconversion | $2/kg U | 22,705 kg U | $45,410 | .01 |
| h) Waste Management | $16/kg U | 23,607 kg U | $377,712 | .07 |
| i) Shipping | | | | |
| b) to c) | $.42/kg U | 103,671 kg U | $43,542 | |
| c) to d) | $.90/kg U | 75,622 kg U | $23,060 | |
| d) to d) | $.72/kg U | 24,981 kg U | $17,986 | |
| f) to g) | $1.45/kg U | 22,705 kg U | $32,922 | |
| Shipping total | - | - | $117,510 | .02 |
| Subtotal | | | $20,783,897 | 3.65 |
| j) Fuel Inventory Carrying Charge (12 percent) | | | $7,497,522 | 1.32 |
| k) Safeguarding | | | NA | - |
| l) Insurance | | | NA | - |
| Total (excluding k and l) | | | $28,281,419 | 4.97 |

Assumptions
Load factor = .65
Burnup = 30,000 MW(t)D/MTU
Efficiency = 33.5 percent
Inflation rate = 7 percent

If the SWU cost of $64.91 in 1974 was inflated annually at five percent instead of seven percent, the 1980 SWU cost would result in an annual enrichment charge of $8,938,815 or 1.57 mills/kwhe. The total cycle cost would be 4.79 mills/kwhe.

Source: Table III-3

plant, and an efficiency rating of 32.5 percent. Table III-4 shows the fuel cycle costs if the AEC characteristics are used. The costs, quoted in 1980 dollars, show a total fuel cycle cost of 6.87 mills/kwhe. This is implied from an annual cost of $48,130,992. The cost is 1.9 mills greater than that found for the model plant.

In general, the higher the burnup rate the lower the demand for uranium feed. Therefore, when a high burnup rate is used, the result is a lower fuel cycle cost, both in total cost and in mills/kwhe. In order to introduce a bias toward low costs, the model nuclear plant is assumed to have high ten-year, levelized burnup. Table III-7 shows the uranium flow for the typical 1,000 MWe light water reactor.

Table III-9 is a summary of the equations used to estimate the uranium flow in the model reactor. The method involved in calculating the amount of uranium entering each stage of the cycle is based on the method for deriving the fuel requirements for the nuclear reactor alone. Basically, it involves dividing the nuclear plant's electrical generating capacity by the nuclear core's fuel burnup rate and the plant's thermal to electrical conversion efficiency. In order to estimate the margin of error in this method, it was used on specific AEC data in order to compare the results with those reported by the AEC. It was found that if the plant assumptions used in this study are fitted into the equation for deriving fuel loading levels as estimated by the AEC, an error of 0.36 percent is found. The difference amounts to 168 kilograms.

Assumptions concerning the operational and technical parameters of a nuclear power plant play a major role in determining fuel cycle costs. Assuming a load factor of 0.80, a burnup rate of 20,333 MW(t)D/MTU, and an efficiency of 32.5 percent, 1980 fuel cycle costs for an average 1,000 MWe

TABLE III-4

1980 Fuel Cycle Costs for an
Average 1000 MWe Nuclear
Power Plant Based on Historic
AEC Assumptions[1] (1980 dollars)

| Cost Component | Cost/Unit | Quantity/Yr. | Cost/Yr. | mills/kwhe |
|---|---|---|---|---|
| a) Mining and Milling | \$20/lb $U_3O_8$ | 507 122 lbs $U_3O_8$ | \$10,142,440 | 1.45 |
| b) Conversion to $UF_6$ | \$5/kg U | 195 025 kg U | \$975,125 | 0.14 |
| c) Enrichment | \$97/kg SWU | 192 317 kg SWU | \$18,654,749 | 2.66 |
| d) Fuel Prep and Fabrication | \$112/kg U | 47 960 kg U | \$5,371,520 | 0.77 |
| e) Spent Fuel Shipping | \$8/kg U | 42 929 kg U | \$343,432 | 0.05 |
| f) Reprocessing | \$56/kg U | 42 929 kg U | \$2,404,024 | 0.34 |
| g) Reconversion | \$2/kg U | 42,500 kg U | \$85,000 | 0.01 |
| h) Waste Management (reactor fuel) | \$16/kg U | 44,189 kg U | \$707,024 | 0.10 |
| i) Shipping | | | | |
| b) to c) | \$.42/kg U | 194,050 kg U | \$81,501 | |
| c) to d) | \$.90/kg U | 47,960 kg U | \$43,164 | |
| d) to d) | \$.72/kg U | 46,761 kg U | \$33,668 | |
| f) to g) | \$1.45/kg U | 42,500 kg U | \$61,625 | |
| Shipping total | - | - | \$219,958 | 0.03 |
| Subtotal | | | \$38,903,272 | 5.55 |
| j) Fuel Inventory Carrying Charge (at 12%) | | | \$9,227,720 | 1.32 |
| k) Safeguarding | | | NA | - |
| l) Insurance | | | NA | - |
| Total (excluding k and l) | | | \$48,130,992 | 6.87 |

Assumptions (AEC; historical)
Load factor = .80
Burnup = 20,333 MW(t)D/MTU
Efficiency = 32.5 percent
Inflation rate = 7 percent annually

Sources: Tables III-3, IIIA-1 and IIIA-4.
(1) Atomic Energy Commission, Reactor Fuel Cycle Costs for Nuclear Power, WASH-1099, December 1971, p. 134 and Atomic Energy Commission, The Nuclear Industry, 1973, WASH-1174-73 (1973), p. 15.

**TABLE III-7**

**Uranium Flow for a Typical**
**1000 MWe Light Water Reactor**

| | | Uranium Kg/Year | Percentage Weight of $U^{235}$ | SWU/Year |
|---|---|---|---|---|
| Conversion | (in) | 104 192 | .711 | |
| (0.5% loss) | (out) | 103 671 | .711 | |
| Enrichment | (regular in) | 103 671 | .711 | |
| | (regular out) | 18 922 | 3.0 | 81 478 |
| | (recycled in) | 22 636 | .85 | |
| | (recycled out) | 4 939 | 3.0 | 21 267 |
| | (out) | 23 861 | 3.0 | 102 745 |
| Recycled U | | 1 761 | 3.0 | |
| Fuel Preparation | (in) | 25 622 | 3.0 | |
| (2% recycled) | (recycled) | 512 | 3.0 | |
| (0.5% loss) | (out) | 24 981 | 3.0 | |
| Fabrication | (in) | 24 981 | 3.0 | |
| (5% recycled) | (recycled) | 1 249 | 3.0 | |
| (0.5% loss) | (out) | 23 607 | 3.0 | |
| Reactor | (in) | 23 607 | 3.0 | |
| | (out) | 22 934 | .85 | |
| Reprocessing | (in) | 22 934 | .85 | |
| (1% loss) | (out) | 22 705 | .85 | |
| Conversion | (in) | 22 705 | .85 | |
| (0.3% loss) | (out) | 22 636 | .85 | |
| Enrichment | (in) | 22 636 | .85 | |
| | (tails) | 17 697 | .20 | |
| | (out) | 4 939 | 3.0 | 21 267 |

Assumptions:

Load Factor = .65
Burnup = 30,000 MW(t)D/MTU
Efficiency = 33.5 percent
104,192 KgU = 122,871 Kg$U_3O_8$ = 270,930 lbs $U_3O_8$
Enrichment tails assay = 0.20 percent $U^{235}$

Source: Table III-9

TABLE III-9

Equations for Deriving the
Annual Uranium Flow for a Typical
1000 MWe Light Water Reactor

| | | Equations for Deriving Kilograms U/yr. | $U^{235}$ Percent Weight | Formulas for Deriving SWU's/yr. |
|---|---|---|---|---|
| Conversion | (in) | U = N/.995 | .711 | |
| (0.5% loss) | (out) | N | .711 | |
| Enrichment | (regular in) | N = (5.479)B | .711 | |
| | (regular out) | B = Enr -S | 3.0 | B(4.306) |
| | (recycled in) | E | .85 | |
| | (recycled out) | S | 3.0 | S(4.306) |
| | (out) | Enr=P-r | 3.0 | Enr(4.306) |
| Recycled U | | r = (0.02P)+(0.05F) | 3.0 | |
| Fuel Preparation | (in) | P = F/.975 | 3.0 | |
| (2% recycled) | (recycled) | (0.02)P | 3.0 | |
| (0.5% loss) | (out) | F | 3.0 | |
| Fabrication | (in) | F = R/.945 | 3.0 | |
| (5% recycled) | (recycled) | (0.05)F | 3.0 | |
| (0.5% loss) | (out) | R | 3.0 | |
| Reactor | (in) | $R=\frac{(e)(k)(8760hrs)}{(b)(eff)(24hrs/day)}$ | 3.0 | |
| | (out) | D=(0.97)R | .85 | |
| Reprocessing | (in) | D | .85 | |
| (1% loss) | (out) | C=(0.99)D | .85 | |
| Conversion | (in) | C | .85 | |
| (0.3% loss) | (out) | E=(0.997)C | .85 | |
| Enrichment | (in) | E | .85 | |
| | (tails) | E-S | .2 | |
| | (out) | S=E/4.583 | 3.0 | |

Sources: Atomic Energy Commission, Reactor Fuel Cycle Costs for Nuclear Evaluation, WASH-1099, Dec. 1971, p. 134.

Atomic Energy Commission, Forecast of Growth of Nuclear Power, WASH-1139, January 1971, p. 18.

U.S. Congress, Joint Committee on Atomic Energy, Future Structure of the Uranium Enrichment Industry, Hearings, 93 Cong. 1 Sess., Phase I, July 31 and August 1, 1973, p. 39.

TABLE III-9 Continued

Notation

| | | |
|---|---|---|
| U | = | kilograms of natural uranium entering conversion (leaving the mill) |
| N | = | kilograms of natural uranium entering enrichment (leaving conversion) |
| B | = | kilograms of enriched uranium leaving regular enrichment |
| E | = | kilograms of spent uranium entering (re) enrichment (leaving (re)conversion) |
| S | = | kilograms of enriched uranium leaving (re) enrichment |
| Enr | = | kilograms of enriched uranium leaving total enrichment |
| r | = | kilograms of recycled uranium from fuel preparation and fabrication |
| P | = | kilograms of enriched uranium entering fuel preparation |
| F | = | kilograms of enriched uranium entering fabrication (leaving fuel preparation) |
| R | = | kilograms of enriched uranium entering the reactor (leaving fabrication) |
| D | = | kilograms of spent uranium entering reprocessing (leaving the reactor) |
| C | = | kilograms of spent uranium entering (re) conversion (leaving reprocessing) |
| e | = | nuclear plant size (megawatts of electricity) |
| k | = | nuclear plant availability factor |
| b | = | levelized nuclear core burnup rate (MW(t)days/MTU) |
| eff | = | the nuclear reactor's thermal to electrical conversion efficiency [MW(e) / MW(t)] |

nuclear power plant were found to be 4.95 mills/kwhe. If the burnup rate was increased to 30,000, costs fell to 3.56 mills/kwhe. If, in addition to the high burnup rate, the efficiency were raised from 32.5 to 33.5 percent and the load factor were decreased from 0.80 to 0.65, the cost in mills/kwhe fell another 0.03.

Data supplied by C. E. Larson, Commissioner, Atomic Energy Commission, yielded fuel cycle costs approximately equal to those found for the model plant considered in this study. Furthermore, the calculated average burnup rates and efficiency levels served to justify those assumed for the model plant. The load factor was higher than that found historically, but this has little affect on total fuel cycle costs. Based on the data provided by Commissioner Larson, over a 30 year period the model nuclear power plant would experience a fuel cycle cost of 4.96 mills/kwhe. This cost, in terms of 1980 dollars, may be compared with the cost of 4.97 mills/kwhe for the model plant developed in this study. If the fuel cycle costs for the nuclear plant using Commissioner Larson's assumptions were assessed after ten years of operation, the fuel cycle cost would be 5.22 mills/kwhe.

Based on data supplied by Commissioner C. E. Larson, it was estimated that the fuel cycle costs for a boiling water reactor in 1980 were 4.99 mills/kwhe. For a pressurized water reactor these costs were 4.91 mills/kwhe. The fuel cycle costs for the model plant analyzed in this study were 4.97 mills/kwhe, falling within these bounds. Again, it should be recalled that the model plant is assumed to consist of the average characteristics of two pressurized water reactors and one boiling water reactor. The differences in cost between the two plant types is small and can be traced to differences in core burnup rates and the required enrichment level of the reactor fuel. A BWR requires more feed at the

reactor, but since the enrichment level of the feed is lower than that required for a PWR, the natural uranium requirements are lower.

## 4. Uranium Costs

a. Uranium Reserves - Reserve estimates are price dependent. The higher the uranium price goes, the larger published reserves become. When price increases justify a cost increase, companies tend to find that their accessible reserves double because there are now more accessible areas to mine. Table IV-1, based on U.S. Geological Survey data, shows reserve and resource estimates for 1972. In the table the identification of the resource by type is based on the assumption of an $8 cost. The tonnages quoted include not only the economically recoverable reserves, but resources which are not recoverable at the $8 price. If, for example, the basic cost were $10, identified sub-marginal resources (at an $8 base) become identified recoverable reserves. Finally, the price base used in the table refers not to the mine price for ore but to the concentrated ore price at the mill; the yellowcake price. The inclusion of uranium recovery from phosphate rock is based on a process which has now become commercial.

Even if the discussion is limited to conventional sources of uranium, many areas of the U.S. have not been explored. Furthermore, the AEC has acknowledged suggestions that its estimates of potential uranium resources may be too conservative.

Recent worldwide interest in nuclear power has caused an increase in uranium exploration. Early results of this effort are shown in Table IV-4. It can be seen that over a four year period, total resources estimated to be available at costs up to $10/pound $U_3O_8$ increased from 1,720,000 tons

TABLE IV-1

U.S. Uranium Resources and Reserves (1972)

| Price/Pound $U_3O_8$ | Short Tons | Short Tons (Cumulative) | Identification ($8.00 per pound base) |
|---|---|---|---|
| ≤$8.00 | 250,000 | 250,000 | Conventional, identified recoverable resources (± 20 percent) |
| ≤$10.00 | 50,000 | 300,000 | Conventional, identified submarginal resources. |
| $10.00 - $15.00 | 150,000 | 1,450,000 | Conventional, identified submarginal resources. |
| | 1,000,000 | | Identified, paramarginal resources from phosphate rock. |
| >$20.00 | 500,000 | 6,950,000 | Undiscovered, conventional resources in known districts. |
| | 5,000,000 | | Identified submarginal resources from phosphate rock. |

Source: P.K. Theobald, et al, in U.S. Geological Survey, Energy Resources of the United States, Circular 650, 1972, pp. 23-24.

Note: Undiscovered conventional recoverable resources in known districts (500,000 tons) and undiscovered conventional submarginal resources in known districts (400,000 tons) are both subject to an error factor of 2; they may be twice as large or only one-half as large.

to 2,300,000 tons. Significant increases occurred in the U.S. and Australia. It must be emphasized that uranium exploration in the rest of the world is at a much earlier stage than U.S. exploration. It is likely that much more uranium will be found.

Estimates of uranium resources in the U.S.S.R. plus China are reported to be at least equal to those of the U.S. plus Canada. If, therefore, one takes 1,500,000 short tons as the estimate for the latter two countries (at a $10/pound cutoff) and assumes a distribution of phosphate rock similar to that of the U.S., then, if the $U_3O_8$ price becomes $20/ pound, the estimate of world resources, excluding the East Bloc, increases from 2,300,000 tons to at least 11,109,000 tons; including the East Bloc increases the total to 18,354,000 tons.

b. Uranium Prices - There does not appear to be any long run shortage of uranium ore. Therefore, it is necessary to find some explanation for the observed rapid increase in yellowcake prices. Possible explanations include: demand greater than short term supply at current prices, lack of competition in the domestic producers' market, cartelization in the rest of the world, and specific actions and implied goals of the AEC.

Historically the uranium market has been soft. Price problems existed until late 1973. There was a free market but power schedule slippages resulted in a short term pile-up of $U_3O_8$ inventories. Future prices might have gone down but for the embargo on imports and the regulations concerning plutonium recycle. By December 1973, however, Nuclear Industry was reporting a rapid increase in medium to long term contracts which started in June. AEC forecasted demand levels for yellowcake continued upward despite nuclear power

TABLE IV-4

Estimated World Resources of Uranium Available at Costs Less than $10/lb. $U_3O_8$
(thousand tons)

| | 1970 Estimates | | | 1974 Estimates | | |
|---|---|---|---|---|---|---|
| | Reserves | Estimated Additional | Total | Reserves | Estimated Additional | Total |
| Argentina | 10 | 22 | 32 | | | |
| Australia | 22 | 7 | 29 | 140 | 48 | 188 |
| Brazil | 1 | 1 | 2 | | | |
| Canada | 232 | 230 | 462 | 241 | 247 | 488 |
| Central African Republic | 10 | 10 | 20 | | | |
| France | 45 | 25 | 70 | 47 | 31 | 78 |
| Gabon | 14 | 6 | 20 | 26 | 6 | 32 |
| Italy | 2 | | 2 | | | |
| Japan | 3 | | 3 | | | |
| Mexico | 1 | | 1 | | | |
| Niger | 26 | 39 | 65 | 52 | 26 | 76 |
| Portugal | 10 | 8 | 18 | | | |
| South Africa | 200 | 15 | 215 | 263 | 10 | 273 |
| Spain | 11 | | 11 | | | |
| U.S.A. | 250 | 510 | 760 | 340 | 700 | 1040 |
| Others (non-Communist) | 4 | 11 | 15 | 68 | 69 | 137 |
| Total (Rounded) | 840 | 880 | 1720 | 1180 | 1140 | 2300 |

Sources: 1970 estimates: European Nuclear Energy Agency and the International Atomic Energy Agency, Uranium Resources, Production and Demand (Organization for Economic Cooperation and Development), September 1970, p. 11.

1974 estimates: Atomic Industrial Forum, Nuclear Industry, March 1974, p. 7.

plant delays and curtailments. On the supply side, short term problems were expected due to an eight year lead time between exploration and the construction of milling capacity. It was reported that, as producers needed adequate prices to cover exploration, development and profits, utilities and the government could help finance exploration and development. As the rate of demand increase was slackening, this does not appear to be sufficient to explain the increasing price for long term future contracts.

One critical element was omitted: the price and availability of competing fuels. Nuclear power is limited to electric utilities and a few military and demonstration propulsion units. In utilities it competes with coal, residual fuel oil, and natural gas. In propulsion it competes with diesel fuel oil.

Prices of natural gas have been controlled by government fiat. The result has been that for existing contracts, the price is relatively low. For new contracts, if supplies are unavailable, the price may be considered infinite.

The use of coal has been limited by air pollution control regulations and the relative lack of government support for research and development on stack gas scrubbers, liquefication and gasification compared to the support levels for nuclear power. Low sulfur coal is in short supply. Its price includes the scarcity factor and the cost of transportation. The latter is high given the distance of western coal from the major consuming markets.

The price of residual fuel oil reflects the current price of crude oil and the greater returns derived from minimizing the output of residual oil by increasing the output of the other fuel components contained in a barrel of crude. The percentage of residual oil produced from a barrel of crude in the U.S. has been falling slowly but steadily. The

need to desulfurize the oil has increased its price. While it does not appear likely that crude oil prices will remain at present levels, in the absence of the consuming countries' effectively ratifying some form of world price stabilization agreement, there is still a question of supply security. Protective measure would add to the cost.

Diesel oil is essentially the same as No. 2 home heating oil. Demand for the latter has been rising as home owners, utilities and industry seek to offset the shortage of natural gas.

Government policy has not been antagonistic to high international oil prices. The higher are such prices, the greater the price umbrella over the high cost of domestic oil, over U.S. coal, and over nuclear power. It must be noted, however, that the prices of foreign and domestic competing fuels are alien to the supply-demand arguments of the AEC and the uranium producers. These arguments are couched in terms of the supply and anticipated demand for uranium alone. The competing fuels argument suggests that the price of uranium can be high because the price of other fuels is high. This would be true even if the costs of uranium production were very low. The AEC-producer argument is that uranium prices must be high if we are to get more of it. It appears, however, that the current world surplus of low cost uranium is a factor against which the industry must be protected.

An added element in the price increases is the lack of competition in the uranium market. The bottleneck in the U.S. appears to be in the number of uranium mills which concentrate the ore. However many independent mining operations exist, the ore is concentrated in relatively few milling plants. Virtually all of these are also engaged in mining operations. Of the total of 16 firms, the largest 8 account

for over 77 percent of the nominal milling capacity in the U.S. The largest 4 account for almost 52 percent. This situation is best described as oligopolistic. One would expect an absence of individual price competition.

On the international market, Nuclear Industry reports evidence of a supply cartel with South African, French, Canadian and Australian membership. They cite a decline in the number of firm quotes available for post-1980 delivery. Members only offer options to buy with prices to be negotiated later and an agreement to raise prices for late 1970's delivery.

By its own activities, the AEC has had an effect on uranium prices. These include the disposal of AEC uranium stocks, the embargo on foreign uranium supplies, and the emphasis on the breeder reactor.

In 1972, the AEC had a stock of 50,000 tons of $U_3O_8$. Rather than auction this off, thereby reducing the prices or maintaining a low one, the AEC elected to run down the stock slowly. The method used was to specify a low transactions tails assay for enrichment, use a considerably higher assay for operations and make up the increased fuel requirement out of its own stocks.

The embargo on foreign uranium supplies was based on the AEC refusal to enrich foreign uranium for use in domestic reactors. As long as foreign enrichment facilities are inadequate, this is tantamount to an embargo on foreign uranium in general. The AEC proposes to enrich foreign uranium in 1977 for domestic use.

The arguments for and against the embargo are as traditional as the results: (1) There is an oversupply of uranium in both the foreign and domestic markets. It is expected to last no later than the 1980's, but meanwhile the embargo is needed to help domestic producers, (i.e., raise

prices). (2) Small producers need access to land, capital and a market. (3) Foreign imports would allow the enormous foreign reserves to preempt the domestic market with concomitant high security risks. Foreign producers could sell uranium in the U.S. at the price of $8/pound, while domestic producers in meeting the price would irretrievably lose hundreds of millions of pounds of associated $10-$15/pound reserves in operating mines.

The success of the cartelization, reduction of domestic competition, embargo and stockpile disposal can be seen in a lack of responses to current bid solicitations. There is no lack of a market to account for the unresponsiveness. Spot prices during the period from 1968 to 1972 averaged $5.75-$6.00/pound. Buyers do not want to pay $8 prices, much less $10-$11 prices. However, at these prices producers report little incentive to explore or add new capacity. Given the current situation, it pays to speculate on future prices by holding on to current reserves. In this, producers are backed by the embargo and the absence of competing fuels: coal because of air pollution control regulations and the lack of support of stack gas scrubber development, gasification and liquefication and oil due to price and a shortfall in domestic refinery capacity. It remains to be seen how permanent are these conditions.

The AEC has consistently underestimated future nuclear power costs. This leads to low quotations of consumer power costs in terms of mills/kwhe. It also makes nuclear power appear very competitive. Only in the area of uranium is the AEC prepared to support and ratify higher prices. This represents a reversal of the whole thrust of AEC actions and implied goals. A consistent explanation can be made in terms of the shift in AEC emphasis from light water reactors to the liquid metal fast breeder reactors.

Dr. Dixie Lee Ray has pointed out that breeder economics does not depend only upon the cost of construction and operating costs of the plant. It also depends on the entire fuel cycle including the design and testing of advanced fuels. The issue may be put more concisely. The breeder reactor has a higher capital cost and a lower fuel cost than a light water reactor. Therefore, for commerical operation, the present discounted value of the fuel saving must be greater than the present discounted value of the extra capital expenditures. The higher the capital cost rises for the breeder, including research, development, cost overruns and inflation, the greater must be the price of natural and/or enriched uranium if the program is to be justified on commercial grounds.

5. Fuel Cycle Component Costs

In this section background material concerning component fuel cycle costs, other than uranium, are discussed. Although much of the data are qualitative, they show that the unit costs used in this study are conservative.

a. Uranium Hexafloride Conversion - The use of AEC stockpiled uranium to reduce the separative work unit demand of utilities reduces the cost to the utilities. However, this is at the expense of commercial conversion plants. Given the difference between government and private costs, to the extent that the government's stockpile is used, the costs of conversion previously cited in this study are lower than those based on fully private usage. This may be considered a subsidy to toll customers. When government stocks are exhausted, average conversion costs will rise.

<u>b. Uranium Enrichment</u> - Whether enrichment plants are privately or governmentally owned, as the demand for separative work units rises, the price of these units would not rise rapidly until capacity is approached unless incremental costs of operation are rising at a faster rate than output. As capacity is reached, rationing by the price system becomes necessary. It is at this point in time that new plants, either public or private, must be built and a new price structure developed. Therefore, it is important to determine when the existing enrichment plants will reach full capacity. Therefore, an evaluation of spare enrichment capacity is important with respect to the price of separative work units because it determines whether or not the price should be based on existing enrichment facilities or on the cost of construction, public or private, of new enrichment facilities. The decision is current because it takes approximately 6-1/2 years to construct a diffusion plant or 5-1/2 years to construct a gas centrifuge plant. The power for the diffusion plant must be provided by the construction of new electric utility capacity. Assuming that these are nuclear the time horizon is approximately nine years. AEC estimates of U.S. enrichment capacity are presented in Table V-1.

It must be emphasized that this table depends upon a number of highly specific assumptions. In particular these include: the forecasted number of nuclear power plants to be built in the future, the amount of material available for reprocessing and the time lag for reprocessing, the amount of plutonium that can be recycled, the dating of the breeder reactor program, and the amount of U.S. enrichment services to be supplied for foreign reactors.

Using AEC cost estimates for a gaseous diffusion plant with a capacity of 8.75 million SWU/year, at a new site, and escalating at an annual rate of 7 percent from FY 1974 to

TABLE V-1

U.S. Enrichment Capacity - AEC Projection

Cumulative Separative Work

($10^6$ SWU)

| Through FY | (1) Committed | (2) Available | (3) (2)-(1) | (4) (3)/(2) (Percent) |
|---|---|---|---|---|
| 1974 | 12.0 | 27.7 | 15.7 | 56.7 |
| 1975 | 20.4 | 41.9 | 21.5 | 51.3 |
| 1976 | 29.3 | 57.6 | 28.3 | 49.1 |
| 1977 | 38.7 | 75.7 | 37.0 | 48.9 |
| 1978 | 49.7 | 95.5 | 45.8 | 48.0 |
| 1979 | 60.4 | 116.1 | 55.7 | 48.0 |
| 1980 | 71.7 | 139.7 | 68.0 | 48.7 |
| 1981 | 83.8 | 165.3 | 81.5 | 49.3 |
| 1982 | 96.2 | 192.2 | 96.0 | 50.0 |
| 1983 | 108.5 | 219.4 | 110.9 | 50.5 |
| 1984 | 120.7 | 247.1 | 126.4 | 51.2 |
| 1985 | 132.4 | 278.8 | 142.4 | 51.8 |
| 1986 | 144.7 | 302.6 | 157.9 | 52.2 |

Source: Atomic Industrial Forum, Nuclear Industry, December 1973, p. 19.

Note: Committed includes: non-power and other domestic and foreign requirements contract, other foreigh agreements and domestic fixed commitment contracts.

FY 1980, capital costs for the plant, including CIP technology, are $2.1 billion. For a gaseous diffusion plant using advanced technology, the cost in 1980 is $1.8 billion. These costs exclude in-plant uranium feed and enriched product inventories and preproduction. Furthermore, the estimates are for a government rather than a private plant. Therefore, the costs exclude taxes, royalties, research and development, and the cost differential of money in the private sector. Finally, the costs include the enrichment plant alone. They do not include the necessary power plants required to serve a gaseous diffusion plant. The AEC estimates that it requires 3.3 kw/SWU capacity at these gaseous diffusion plants.

One of the capital problems involved in the private development of enrichment facilities is that, assuming that plutomium recycle and/or the breeder reactor become generally available, the facilities may not be needed after 2020 or 2030. Therefore, companies building enrichment plants in the 1980's and 1990's, must recover costs in a short period of time.

From the point of view of the utilities, there is an expressed fear that private companies entering this sector will be so few as to be monopolistic. From the point of view of the companies potentially entering the enrichment business, they must obtain the results of research, development and expertise from the government for either the gaseous diffusion or the gas centrifuge enrichment operation. Problems exist concerning classified information and costs. The companies appear to want subsidization, either directly or through AEC purchase of the output of enriched uranium at negotiated (i.e., non-market) prices.

Government and private industry differ somewhat in their estimates of future separative work unit charges. Government

estimates for government owned new gaseous diffusion plants range from $51.08 to $60.82/SWU, in 1974 dollars. The government estimate of charges at a privately owned plant is $64.91/SWU. The price estimate for a gas centrifuge plant is lower but with a relatively wider range. If the government's gaseous diffusion plant estimates for separative work unit charges are escalated at 7 percent to 1980, the range for the publicly owned plant is $76.66 to $91.27/SWU. A newly built private plant would charge $97.41/SWU. The 1980 enrichment charges used in this study were $97.00. Commonwealth Edison, based on escalation of data provided by the Atomic Industrial Forum, estimates 1980 separative work units charges at $70-$80/SWU. It should be noted that in light of increasing electric power and construction costs, the AEC has again revised its separative work unit charges upwards. The estimates for 1980 and subsequent dates are now significantly closer to those predicted in this study.

c. Reprocessing Costs - Even though competition is very limited in this market, processors have in the past had some serious problems. The major one was that as long as the price of yellowcake was low, utilities were unwilling to place forward orders for reprocessing spent fuel. Uranium from natural feed was available when needed. As the price of uranium rises, reprocessing becomes a more realistic activity for the utilities. Secondly, reprocessors have not given very much economic incentive to the utilities in the past.

The future of recycling is somewhat sketchy, primarily because conditions under which recycling is to be permitted are not yet fully defined. The major problem appears to be the form which the recycled manufactured product will take. This may be changed by AEC fuel restrictions.

Currently, there is no reprocessing and the AEC has initiated a nationwide check for additional storage capacity for the unanticipated accumulation of fuel waiting to be reprocessed. The reprocessing crunch is expected by the late 1970's. Utilities therefore are carrying a very large inventory of spent fuel and may wait years before reprocessing. Nuclear Fuels Services is currently holding unreprocessed fuel for four years and may hold it for another five years before it is returned to the utilities that own it. As the reprocessing of spent fuel is expected to be cheaper than that of the enrichment of fuel from fresh feed, one can assign either a high cost to reprocessing or additional costs to enrichment.

d. Plutonium Recycling - Currently, there is no plutonium recycling. It would appear that, rather than consider plutonium used in commercial reactors as a credit to be deducted from the fuel cycle costs, the production of plutonium from $U^{238}$ involves either an inventory cost or a disposal cost. As the AEC has not yet indicated what conditions must be met for permission to recycle plutonium, there is no way to make firm price commitments for recycling. Even by 1980, it is not expected that there will be much recycling so that storage must be found for over 50 tons of plutonium.

e. Other Costs - Additional costs are associated with transportation, waste management of both plutonium contaminated wastes and high level wastes, and safeguarding. The problems associated with all of these, and the inherent increase in costs, are due to a lack of firm guidelines and practical solutions. For example, the AEC considers that it has sufficient knowledge to develop permanent salt-bedded waste disposal. However, if high level wastes are not salt

bedded, other means for the long term are considered either impractical or too expensive, unless the highest level radioactive waste material is removed.

## 6. Capital and Related Costs

The Atomic Industrial Forum has indicated that capital costs were $130/kw in May 1967, $220/kw in June 1969, and $330/kw in January 1971. Presumably these costs will not continue to escalate at the increasing rate implied by this history. Using the first pair implies capital costs of about $562/kw in 1980, using the second two implies a 1980 capital cost of $780/kw. Consideration of the rate of change of the increase yields much higher capital costs. In testimony before the Joint Committee on Atomic Energy, AEC Commissioner Larson reported that estimates of capital costs have risen from about $125/kw installed to over $500/kw of installed capacity at some plants.

By far the most detailed analysis of direct construction costs, only a part of capital costs, is to be found in AEC document WASH-1230, Volumes I and II. These indicate that for a 1,000 MWe boiling water reactor, in 1971 the total base construction costs were $211,963,200. For a 1,000 MWe pressurized water reactor, the total base construction costs were $210,483,000. Escalating these costs at 7 percent from January 1971 to January 1980, implies costs of $389,680,000 and $386,960,000, respectively. The document recommends that the prices must also be adjusted for contingency costs, including material, labor and professional services, and for escalation and interest charges during construction. Furthermore, the estimates exclude the cost of land and land rights and assume the unrestricted availability of water, once-through cooling, no provision for extended discharge, and no provision for restricted intake velocity or dilution in the cooling systems.

If cooling towers must be added, additional costs are incurred. It is difficult to assess the cost of cooling towers because what is included is not always specified. However, costs for closed cycle towers have been reported in the range from $4-20 million, with average costs of $8-$10 per kilowatt for a mechanical draft, and $12-$15 per kilowatt for natural draft towers.

With the new emphasis on nuclear safety, additional costs will be incurred. These will be in the area of emergency core cooling systems, treatment of radioactive wastes, and decommissioning. Considering only emergency core cooling systems, an early estimate of the cost of AEC rule changes included an average 5 percent derating of all reactors through mid-1976, plus approximately $93 million for replacement power and $70 million per 1,000 MWe reactor for modifications and bringing the plant back to 100 percent of rated capacity. Moreover there would be a fuel cost penalty of approximately $520,000/year/1,000 MWe reactor, and $215,000/year/500 MWe reactor. If further derated, capacity and replacement power penalties are expected to increase substantially. It is possible that, subsequent to the tests on the emergency core cooling system hardware, additional changes in regulations and requirements will be made. These will further increase costs of construction and retrofit.

## 7. Project Independence: The Energy Costs of Nuclear Power

Based on the two technical memoranda in Appendix B, Capital and Fuel Cycle Energy Costs of a 1,000 MWe Nuclear Reactor, it was estimated that approximately 14 percent of the annual energy output of a reactor is required to mine, mill, convert, enrich, process, ship and manage the wastes required for fueling the reactor. Additionally, the energy

cost of constructing the reactor is 9.55 trillion Btu, or about 2.79 billion kwh.

A 1,000 MWe reactor uses approximately 50 MWe for in-plant purposes and may, therefore, be rated at 950,000 kwe (net). Over a year the capacity net output is 8.322 billion kwhe. Assuming an availability factor of 0.65, yields an available output of 5.409 billion kwhe.

For purposes of estimating net energy generation for nuclear systems, we must assume that nuclear power must generate sufficient output to compensate for energy input to the system. Therefore, as 14 percent of the energy output equals the energy costs of the fuel cycle, only 4.65 billion kwhe of the 5.409 billion kwhe are available to the non-nuclear system (i.e., to the rest of the economy). If we further assume that the construction costs in energy terms of all new reactors are supplied from the output of existing reactors, we can determine the period required for a reactor to repay the energy costs of its construction. The simple ratio of the energy cost of construction to the annual output available to the rest of the economy shows this to be about 7.2 months.

From this it is possible to estimate the contribution of new nuclear power plants to Project Independence. A simple example may show how this can be done.

Assume: (1) that it costs 2.79 billion kwh to construct each 1,000 MWe plant, (2) that this energy expenditure is evenly divided over a six year construction period (0.465 billion kwh/year), (3) that the available output of the plant is 4.65 billion kwhe and (4) that the energy construction costs are repayed in 7.2 months of the first year's (year 7) operation. Finally, assume that the nuclear building program involves ten new plants in 1975, eleven in 1976, and up to twenty new plants started in 1985. The results are summarized in the following table. With respect to Project Independence, a nuclear program may be an energy sink.

NET ENERGY OUTPUT (COSTS) OF A NUCLEAR PROGRAM
(billions Kwhe)

| | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Number of New Plants Started | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
| Construction Costs - Energy Outlay (Annual) | 4.65 | 9.77 | 15.35 | 21.39 | 27.90 | 34.88 | 37.67 | 40.45 | 43.24 | 46.04 | 48.83 |
| Construction Costs - Energy Outlay (Cumulative) | 4.65 | 14.42 | 29.77 | 51.16 | 79.06 | 113.94 | 151.61 | 192.06 | 235.30 | 281.34 | 330.17 |
| Less Output of the New Plants | 0 | 0 | 0 | 0 | 0 | 0 | 14.73 | 62.70 | 115.32 | 172.59 | 234.52 |
| Cumulative Net National Energy Gain (Loss) | (4.65) | (14.42) | (29.77) | (51.16) | (79.06) | (113.94) | (136.88) | (129.36) | (119.98) | (108.75) | (96.65) |

## D. Publication and Utilization

The foregoing discussion is based on three studies produced with current NSF(RANN) support:

Michael Rieber and Ronald Halcrow, Nuclear Power to 1985: Possible versus Optimistic Estimates, Center for Advanced Computation, University of Illinois at Urbana-Champaign, CAC Document No. 137P, November 1974, pp. 192.

Peter Penner, Input-Output Calculation of Fuel Cycle Energy Costs for the Average Nuclear Power Plant, Center for Advanced Computation, University of Illinois at Urbana-Champaign, CAC Technical Memorandum No. 50, April 1975, pp. 6.

Peter Penner, Summary of Techniques Used for Calculating the Energy Costs of Constructing a Commercial Reactor, Center for Advanced Computation, University of Illinois at Urbana-Champaign, CAC Technical Memorandum No. 51, April 1975, pp. 21.

The first, currently being updated, is included separately as Appendix A. The next two may be found in Appendix B.

A combination of Nuclear Power to 1985 and Low Sulfur Coal: A Revision of Reserve and Supply Estimates, by Michael Rieber, (Center for Advanced Computation, University of Illinois at Urbana-Champaign, CAC Document No. 88), was presented at the Fourth Annual Regulatory Information Systems Conference (September 1974). Entitled, Fuels for Electric Power Generation: Low Sulfur Coal and Enriched Uranium, it will be published in the conference proceedings.

Additionally, at the request of the Missouri Public Service Commission, Professor Rieber prepared testimony on the fuel cycle costs of the proposed Union Electric nuclear power plants. The methodology used was that of the Rieber-Halcrow study, but the actual data are proprietary.

## SECTION III: COAL RESERVES, RESOURCES AND PRODUCTION

Fulfillment of the goals of Project Independence and beyond will require huge short and long term increases in coal output. Given nuclear fuel cycle costs significantly higher than those estimated by the AEC (Section II), and the greatly reduced rate of construction of nuclear facilities, coal will have a much more important place in this Nation's future than that accorded to it by most forecasts (National Petroleum Council, Project Independence, Office of Management and Budget, Atomic Energy Commission and Federal Power Commission.)

Behind the possible production rates are the reserves of coal; their location, amount, accessibility and quality. Behind the reserves are coal resources. Together these determine, not coal prices, but the costs of coal into the foreseeable future.

This section deals primarily with the validation of our coal reserve-resource base. The basic research material may be found in Appendices C and D. Of primary importance to the coal future is an accurate assessment and classification of our reserve-resource position. Unfortunately, we are not yet at that point. For example, one end result of a classification should be the ability to derive from the data any segment of information required for policy, e.g., a report of low sulfur economically recoverable reserves by seam, county, seam thickness, depth and thickness of overburden.

Because of air pollution control, economically recoverable reserves should be further subdivided into sulfur categories based on total sulfur, sulfur types (organic and inor-

ganic), and percent washability. Furthermore, provision should be made for classification by sulfur category on a comparable Btu basis.

The application of standard recovery factors to reserves is inconsistent with reserve estimation as these do not sufficiently discriminate among coals and among habitats. Furthermore, all assumptions concerning equipment capacity, reserves, etc., should be clearly stated to facilitate recalculation of reserves if any parameter(s) changes at a later date. In a statistical sample of 200 underground mines, selected as representative of operating mines, recoverability ranged from 20 to 91 percent. The average recoverability was 57.0 $\pm$ 1.7 percent with a 95 percent confidence limit. These estimates are in the context of 1968 technology and economics. Hence, the traditionally used and quoted recoverability percentage of 50 percent is indiscriminate of all coal deposits. The lower figures supposedly compensated for losses not ordinarily included at the mine.

Reevaluation of reserves or resources as a result of changes in technology and economics may ultimately come in part from mined coal heretofore considered lost. As "lost" coal has a rather permanent connotation, perhaps these quantities should be otherwise categorized. A concept of estimated secondary recovery may be useful. If measured losses had been eliminated in the total tonnage estimates, the Bureau of Mines' estimates would have been based on a 65 percent recoverability factor. This compares favorably with the 65.1 percent average value of recovery made by mine officials.

One result of safety and stripmining legislation is to raise the cost of production. This will not only forestall production in certain areas and/or specific mines, it will decrease that quantity of coal defined as economically

recoverable reserves. However, if the price of coal rises sufficiently to cover reclamation and safety costs, production will recommense and the reserve will again be economically recoverable. The same arguments hold with respect to added costs of production due to increased unionization in western coal fields or shifts of workers between unions.

Strippable reserves should be reported as both the percent and amount strippable. These reserves are currently part of economically recoverable reserves, but may have to be recategorized in the light of anti-strip mine legislation.

Estimates of coal reserves should be divided into total reserves and reserves of low sulfur coal. Based on Bureau of Mines data, our study shows that the reserves of low sulfur coal in the U.S. are about 75 percent lower than published estimates. Reserve estimates of low sulfur coal in the far west should be reduced by 85 percent. The estimating procedure used in the study puts all coal on a common Btu basis, which is what a consumer does for cost comparisons, and reassigns the coal to the corrected sulfur class. It is also shown that if production is concentrated in the low sulfur class, reserves are inadequate to 1985.

The importance of the distinction between high and low sulfur coal arises because sulfur oxide pollution control regulations prohibit the emission of more than 1.2 pounds of $SO_2$ per million Btu's of heat generated by the burning of coal in new plants. To meet this standard, a coal containing 24 MMBtu/ton cannot contain more than 0.7 percent sulfur by weight. Coals with a lower heat value must contain correspondingly less sulfur if they are to meet the standard.

Conventional estimates of resources and reserves (DeCarlo/Mitre/National Petroleum Council) are based on the simple addition of coal tonnages, without regard to heat con-

tent. However, what is important is the heat content. To produce a given amount of heat, a coal with a heat content of 18 MMBtu/ton is worth only three-fourths as much as one containing 24 MMBtu/ton. Unfortunately, to produce a given amount of heat, in consuming the additional tonnage of low Btu coal to make up the Btu differential, the sulfur content of the additional tonnage is also emitted. Therefore, the amount of sulfur in the additional tonnage must be included to determine a comparable sulfur content for both coals. Assuming that both coals contained 0.7 percent sulfur (by weight) on a simple or conventional tonnage basis, only the 24 MMBtu/ton coal would meet air pollution control standards. The 18 MMBtu/ton coal must be rated as if it contained 0.93 percent sulfur. This is the equivalent of shifting the lower Btu coal of the the $\leq$ 0.7 percent sulfur category and into the 0.8-1.0 percent sulfur class.

In order to estimate the reliability of coal reserve estimates, analyses were made of Illinois, Wyoming and Bureau of Mines data. Illinois is a developed coal state, Wyoming is a new coal province. With respect to total coal reserves-resources, analysis indicates that while Illinois estimates are probably the best extant, they are likely to be conservative. Western coal reserve-resource estimates, exemplified by Wyoming, range from good in some limited areas to crude approximations. Their use for predictive policy purposes is limited. The Bureau of Mines' data bank, while extremely helpful for current conditions, employs a methodology that results in a crude overall estimate of reserves. The result is a restricted usefulness for policy.

## A. Low Sulfur Coal: Reserves and Resources

### 1. Summary and Conclusions

Conventionally, the definition of low sulfur coal, on which traditional reserve and supply estimates are based, depends only on the weight of sulfur in a ton of coal. The Btu content of coal is not considered. However, coal purchases and $SO_2$ regulations are based on Btu content. A recalculation of reserve estimates of low sulfur coal on a utility average Btu basis reduces traditional U.S. estimates by over 75 percent and Western estimates by almost 85 percent. When calculated on a Btu basis, maximizing low sulfur coal production results in a supply shortage by 1985. The data revisions are significant for both energy policy planning and air pollution control.

A consumer oriented base of 22.6 million Btu/ton (MMBtu/ton) is used to standardize coal reserves and resources on the basis of heat content. This standardization leads to a small increase in the resource/reserve estimates of bituminous coal and to a large reduction in the estimates of subbituminous coal and lignite. It necessarily leads to a reclassification of the U.S. resources and reserves, conventionally considered low sulfur, to higher sulfur categories. Known recoverable reserves in the $\leq$ 0.7 percent sulfur (weight) category are reduced from a conventional estimate of 68.2 billion tons (DeCarlo/Mitre/National Petroleum Council) to a 16.4 billion tons expressed as equivalent tons of 22.6 MMBtu/ton of coal, that is on a consistent Btu sulfur adjusted basis. The reduction amounts to 76 percent of the conventional estimates of $\leq$ 0.7 percent sulfur coal and 17

percent of the coal in the 0.8-1.0 percent sulfur category. Conventional recoverable reserve estimates of $\leq$ 0.7 percent sulfur coal in the western states are reduced by almost 85 percent.

The revised estimates are also signficant in terms of the future production of low sulfur coal (to 1985). Assuming a maximum annual rate of growth of coal production of 7 percent, cumulative coal production from 1970 through 1985 would, at maximum, be over 17 billion tons. Because of sulfur limitations required by air pollution control regulations, all production is assigned to the lowest sulfur category. Conventional reserve estimates of coal in the $\leq$ 0.7 percent sulfur category indicate that 51.1 billion tons of known recoverable reserves would still be available after 1985. Based on our estimates, known recoverable reserves of $\leq$ 0.7 percent sulfur coal would fall short of the maximum cumulative production by over one billion tons in the same period.

In this study, (see Appendix C, Low Sulfur Coal: A Revision of Reserve and Supply Estimates), several current alternative measures of coal resources and reserves are compared. The estimates are shown to depend on the definitions used for the data collection. Also presented are both the conventional methodology and that used in this study to estimate low sulfur coal resources and reserves. Based on a study made for the Bureau of Mines, the addition to the resource/reserve base made possible by washing to remove sulfur is estimated. This is an attempt to determine what increase in the disappointingly low estimates developed in this study can be made by assuming the generalized use of a current coal preparation technique. If some very optimistic assumptions are made, the overstatement of conventional

resource/reserve estimates of low sulfur coal is only 33 percent. More probable assumptions concluded that, even with washing, the overstatement is about 67 percent. Following an analysis of the production of low sulfur coal, the relationship between coal prices and reserve/resource estimates is developed.

Based on current technology and market conditions, analysis suggests a number of offsetting policy options. In the short-run, end use controls restrict the low sulfur coal available for the electric utility and industrial sectors. An embargo or quota on exports of low sulfur coal could provide about 55-60 million tons for the domestic market. Sales on the open market of low sulfur coal from captive mines depend on the rate at which current output capacity can be increased.

Long-run policy alternatives involve the expanded use of high sulfur coal. This is administratively most easily accomplished by the reduction of air quality standards. Alternatively, efforts leading to the improvement and implementation of gasification, liquefication, solvent refining of coal and/or stack gas scrubbing can be advanced. These last require the additional use of coal; there is a fuel penalty for all, but it is least for scrubbing.

Given the transportation costs of western coal to the midwest, the last four alternatives, all based on indigenous midwestern high sulfur coal, may well be cheaper than western coal burned in the midwest to meet air quality standards. Given the water resources of the Rocky Mountain area it is probable that more sites for coal gasification and liquefication plants can be found in the midwest than in the far west.

## 2. Revised Reserve and Production Estimates - Low Sulfur Coal

The amount of sulfur in coal became economically important following the passage of the Clean Air Act. As a result of this, and succeeding amendments, a limit of 1.2 pounds of sulfur oxide emissions per million Btu's of heat generated was set. At the 1.2 pound $SO_2$ emission limit, a coal containing 24 MMBtu/ton cannot contain more than 0.7 percent sulfur (by weight) and still meet the standard. The result has been a premium price for even nonmetallurgical coals containing 0.7 percent sulfur or less, a shift to other fuels, and some movement towards the technological advancement of scrubbing, solvent refining and coal gasification and liquefication. In part, it is the price differential between low and high sulfur coal that makes these technologies attractive.

While recoverable reserves of coal are adequate to our needs, this is not true with respect to coal with a sulfur content of $\leq$ 0.7 percent. As conventionally estimated, using current combustion technology, little U.S. bituminous coal can meet a 1.2 pounds $SO_2$/MMBtu emission standard. As the 0.7 pound $SO_2$ emission standard is approached, a 12,000 Btu/pound coal could not contain more than about 0.4 percent sulfur by weight in the coal itself. There is very little bituminous coal in the United States that can meet such a standard.

Of equal or greater importance is the overstatement, in conventional estimates, of low sulfur coal in the $\leq$ 0.7 percent sulfur in the fuel category. The same is true of the next class, usually regarded as 0.8 to 1.0 percent sulfur by weight in coal. These overstatements occur because in the basic data estimates of tons of coal of different Btu content

are simply added within sulfur classes. Proper summation of resources requires that adjustments be made. In the course of these adjustments the reserve estimates are altered to account for the Btu content and the sulfur content classification shifts. The published estimates of the Department of the Interior and the Bureau of Mines do not appear to treat these problems.

Table 1 is a corrected version of the Mitre Corporation estimates of resources and recoverable reserves as of January 1, 1965. In the Mitre study, the figures for known reserves come from DeCarlo.[1] The estimates of known recoverable reserves are derived by the Mitre Corporation,[2] while the sulfur content classifications are those of DeCarlo.

Even from Table 1, it is possible to suggest that a casual addition of all coals in the $\leq$ 0.7 percent sulfur content by weight category is not warranted. Known recoverable reserves of lignite in this category amount to almost 56 percent of the entire reserve of all ranks in this sulfur category. However, problems exist in the use of lignite by steam electric power plants such that currently this may be considered more a potential than an actual reserve.[3]

Table 2 is an estimate of known resources and known recoverable reserves, categorized by sulfur content, with all coal tonnages expressed as tons of 22.6 MMBtu/ton coal and the sulfur categories into which the reserves are placed adjusted because of the new Btu basis. A comparison of Tables 1 and 2 indicates that the total of all ranks of coal in the $\leq$ 0.7 percent sulfur content category are, due to the reclassification, reduced by almost 76 percent. Furthermore, the reclassification reduces the reserves of coal in the succeeding class, 0.8 to 1.0 percent sulfur, by almost 17 percent. Comparing Tables 1 and 2 on a regional basis, it

Table 1

United States Coal: Resources and Recoverable Reserves (Jan. 1, 1965)
($10^6$ Short Tons)

| Bituminous Coal | Sulfur Content[1] ≤ 0.7 | 0.8-1.0 | 1.1-1.5 | 1.6-2.0 | 2.1-2.5 | 2.6-3.0 | 3.1-3.5 | 3.6-4.0 | >4.0 | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Appalachian, North | 45 (2) | 2755 | 21370 | 23050 | 27525 | 11950 | 8780 | 7155 | 800 | 103430 |
| | 5 (3) | 360 | 2780 | 2995 | 3580 | 1550 | 1140 | 930 | 105 | 13445 |
| South | 37275 | 41025 | 18135 | 9890 | 2770 | 3510 | 275 | 45 | 85 | 113010 |
| | 4100 | 4510 | 1995 | 1090 | 305 | 385 | 30 | 5 | 10 | 12430 |
| Total | 37320 | 43780 | 39505 | 32940 | 30295 | 15460 | 9055 | 7200 | 885 | 216440 |
| | 4105 | 4870 | 4775 | 4085 | 3885 | 1935 | 1170 | 935 | 115 | 25875 |
| Interior, East[4] | 195 | 781 | 6941 | 6520 | 7770 | 33588 | 69679 | 91233 | 37006 | 253712 |
| | 50 | 195 | 1735 | 1630 | 1942 | 8397 | 17420 | 22808 | 9252 | 63428 |
| West | 250 | 770 | 2475 | 1180 | 9170 | 2070 | 11340 | 28975 | 62635 | 118915 |
| | 20 | 60 | 200 | 95 | 735 | 165 | 905 | 2320 | 5015 | 9515 |
| Total | 445 | 1551 | 9416 | 7700 | 16940 | 35658 | 81019 | 120208 | 99691 | 372627 |
| | 70 | 255 | 1935 | 1725 | 2677 | 8562 | 18325 | 25128 | 14267 | 72943 |
| Rockies, North | 6275 | 6815 | 205 | 395 | 400 | 175 | 40 | 25 | 590 | 14920 |
| | 690 | 750 | 20 | 45 | 45 | 20 | 5 | 0 | 65 | 1640 |
| South | 38940 | 56295 | - | 1525 | - | - | - | - | 3995 | 100755 |
| | 3895 | 5630 | - | 150 | - | - | - | - | 400 | 10075 |
| Total | 45215 | 63110 | 205 | 1920 | 400 | 175 | 40 | 25 | 4585 | 115675 |
| | 4585 | 6380 | 20 | 215 | 45 | 20 | 5 | 0 | 465 | 11715 |
| West Coast[5] | 900 | 685 | - | - | - | - | - | - | - | 1585 |
| | 80 | 60 | - | - | - | - | - | - | - | 140 |
| Bituminous Coal-Total | 83880 | 109126 | 49126 | 42560 | 47635 | 51293 | 90114 | 127433 | 105161 | 706327 |
| | 8840 | 11565 | 6730 | 6025 | 6607 | 10517 | 19500 | 26063 | 14847 | 110673 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Subbituminous Coal | | | | | | | | | | |
| Rockies, North | 129665 | 109045 | - | 1300 | - | - | - | - | 10 | 240020 |
| | 14265 | 11995 | - | 145 | - | - | - | - | - | 26405 |
| South | 52005 | 16910 | 150 | - | - | - | - | - | - | 69115 |
| | 5205 | 1690 | 15 | - | - | - | - | - | - | 6910 |
| Total | 181670 | 125955 | 150 | 1300 | - | - | - | - | 10 | 309135 |
| | 19470 | 13685 | 15 | 145 | - | - | - | - | - | 33315 |
| West Coast(5) | 3780 | 585 | - | - | - | - | - | - | - | 4365 |
| | 340 | 50 | - | - | - | - | - | - | - | 390 |
| Subbituminous Coal-Total | 185450 | 126580 | 150 | 1300 | - | - | - | - | 10 | 313500 |
| | 19810 | 13735 | 15 | 145 | - | - | - | - | - | 33705 |
| Lignite (>98% N. Rockies) | 344620 | 61385 | 41165 | - | - | 465 | - | - | - | 447635 |
| | 37905 | 6750 | 4530 | - | - | 50 | - | - | - | 49235 |
| Anthracite (>95% Pa.) | 12550 | 95 | - | 145 | 285 | - | - | - | - | 13075 |
| | 1630 | 10 | - | 20 | 35 | - | - | - | - | 1695 |
| Total-All Ranks | 626500 | 297186 | 90441 | 44005 | 47920 | 51758 | 90114 | 127433 | 105171 | 1480537 |
| | 68185 | 32060 | 11275 | 6190 | 6642 | 10567 | 19500 | 26063 | 14847 | 195308 |

Source: L. Hoffman, et al, Survey of Coal Availabilities by Sulfur Content, Final Report, the Mitre Corporation, for the Environmental Protection Agency, MTR-6086, (May 1972), Table XVI, p. 22.

(1) Sulfur content is in percent by weight on a dry basis.

(2) The larger number on each line refers to known resources. This includes both known recoverable reserves and known marginal and submarginal resources. It does not include estimates of undiscovered resources.

(3) The smaller number on each line is the Mitre estimate of known recoverable reserves alone; that which can be recovered with present technology and current prices.

(4) Eastern Interior is corrected. Mitre figures are based on J.A. De Carlo, et al, Sulfur Content of United States Coals, Bureau of Mines, IC 8312, (1966), Table A-1, p. 19. This was altered by a revision for the Illinois data in which the reserve estimates for low sulfur coal were modified. See, U.S. Department of Health Education and Welfare, Control Techniques for Sulfur Oxide Air Pollutants, NAPCA No. AP-52, (January 1969), Table 4-2, page 4-11.

(5) Excluding Alaska.

Regions: Northern Appalachia is defined as Pennsylvania, the northern part of West Virginia and Maryland. The southern Appalachian region is composed of eastern Kentucky, the southern part of West Virginia, Tennessee, Virginia and Alabama. The eastern Interior region is made up of Illinois, Indiana, western Kentucky, and Ohio. The western Interior region is composed of Iowa, Kansas, Missouri, Oklahoma, Arkansas, and Texas. The northern Rocky Mountains region is made up of North and South Dakota, Montana, Wyoming, and Idaho. The sourthern Rock Mountains region comprises Colorado, Utah, Arizona, and New Mexico. Finally, the West Coast includes Washington, Oregon, and California; it excludes Alaska.

Table 2

United States Low Sulfur Coal: Resources and Recoverable Reserves (Jan. 1, 1965), Standardized Btu and Effective Sulfur Basis(1)
($10^6$ Short Tons)

| | Sulfur Content | | | |
|---|---|---|---|---|
| | ≤ 0.7 | 0.8-1.0 | 1.1-1.5 | 1.6-2.0 |
| Bituminous Coal | | | | |
| Appalachian, North | 54 | 3306 | 53304 | 33030 |
| | 6 | 432 | 6930 | 4296 |
| South | 44730 | 49230 | 33630 | 3324 |
| | 4920 | 5412 | 3702 | 3666 |
| Total | 44784 | 52536 | 86934 | 36354 |
| | 4926 | 5844 | 10632 | 4662 |
| Interior, East | 207 | 828 | 7357 | 6911 |
| | 53 | 207 | 1839 | 1728 |
| West | 265 | 801 | 2574 | 1227 |
| | 21 | 62 | 208 | 99 |
| Total | 472 | 1629 | 9931 | 8138 |
| | 74 | 269 | 2047 | 1827 |
| Rockies, North | 6526 | 7088 | 213 | 411 |
| | 718 | 780 | 21 | 47 |
| South | 42055 | 60799 | - | 1647 |
| | 4207 | 6080 | - | 162 |
| Total | 48581 | 67887 | 213 | 2058 |
| | 4925 | 6860 | 21 | 209 |
| West Coast | 855 | 651 | - | - |
| | 76 | 57 | - | - |
| Bituminous Coal-Total | 94692 | 122703 | 97078 | 46550 |
| | 10001 | 13030 | 12700 | 6698 |
| Subbituminous Coal | | | | |
| Rockies, North | - | 107622 | 90507 | - |
| | - | 11840 | 9956 | - |
| South | 46329 | 15050 | 133 | - |
| | 4632 | 1504 | 13 | - |
| Total | 46329 | 122672 | 90640 | - |
| | 4632 | 13344 | 9969 | - |
| West Coast | - | 3754 | - | - |
| | - | 335 | - | - |
| Subbituminous Coal-Total | 46329 | 126426 | 90640 | - |
| | 4632 | 13679 | 9969 | - |
| Lignite | - | - | 243603 | - |
| | - | - | 26793 | - |
| Anthracite | 14056 | 106 | - | 162 |
| | 1826 | 11 | - | 22 |
| Total-All Ranks | 155077 | 249235 | 431321 | 46712 |
| | 16459 | 26720 | 49462 | 6720 |

Notes: (1) Equivalent tons of 22.6 MMBtu/ton coal.

can be seen that known recoverable reserves in the east, (defined as the Appalachian and Interior regions) increased by almost 18 percent. This is due primarily to a reevaluation of reserves based on Btu content. In the west (defined as the Rockies and the West Coast excluding Alaska), however, there is an almost 85 percent decrease in the reserves of low sulfur coal in the $\leq$ 0.7 percent sulfur category. While it is true that most of the coal removed from the low sulfur categories is reassigned into higher sulfur categories, absent usage of effective technologies for sulfur removal, because of air pollution control regulations these coals are not further considered here.

Some reduction in the sulfur content of coal may be achieved by crushing and washing. This removes some of the pyritic sulfur at the cost of losing some of the coal. Table 3 indicates the available reserves of low sulfur coal by sulfur content subsequent to washing. The figures in Table 3 should be compared with those in Table 2. The $\bar{x}$ estimate refers to the average sulfur reduction due to washing, the $-1\sigma$ column is a pessimistic evaluation of washing, and the $+1\sigma$ is an optimistic evaluation of the sulfur reduction in coals due to washing. The sulfur content in the fuel after washing depends on the initial sulfur content, the relative amount of pyritic to organic sulfur, and on the dispersion of the pyritic sulfur within the coal. The ranges may be very broad and Table 3 should be viewed primarily as indicative. It does give some idea, however, of what can be achieved with current technology.

Table 4 presents a comparison of coal reserves and resources in the low sulfur category. Column 1 is the conventional form found in DeCarlo/Mitre/National Petroleum Council and others. It represents the simple addition of

Table 3

United States Coal: Resources and Recoverable Reserves
of Low Sulfur Coal After Sulfur Reduction by Washing
(Jan. 1, 1965) - Selected Regions, Standardized Basis
($10^6$ Short Tons)

| | Sulfur Content (Percent) | | | | | |
|---|---|---|---|---|---|---|
| | ≤ 0.7 | | | 0.8-1.0 | | |
| | $-1\sigma$ | $\bar{x}$ | $+1\sigma$ | $-1\sigma$ | $\bar{x}$ | $+1\sigma$ |
| Appalachian, North | 3360 | 3360 | 29004 | 25644 | 25644 | 27660 |
| | 438 | 438 | 3774 | 3336 | 3336 | 3594 |
| South | 44730 | 93960 | 93960 | 49230 | 21762 | 21762 |
| | 4920 | 10332 | 10332 | 5412 | 2394 | 2394 |
| Total | 48090 | 97320 | 122964 | 74874 | 47406 | 49422 |
| | 5358 | 10770 | 14106 | 8748 | 5730 | 5988 |
| Interior, Total | 472 | 2101 | 2101 | 1629 | 9931 | 9931 |
| | 74 | 343 | 343 | 269 | 2047 | 2047 |
| Rockies, Total | 94910 | 94910 | 285469 | 190559 | 490364 | 622184 |
| | 9557 | 9557 | 29761 | 20204 | 53177 | 67457 |

Note: Anthracite is excluded. Estimates are expressed
as equivalent tons of 22.6 MMBtu/ton coal.

tonnage without regard to Btu content. Column 2 is the revision of the first column based on a standardized Btu content and the resultant reclassification of the reserves in terms of sulfur category. Columns 3-5 indicate the size of the standardized reserves (Column 2) given specific assumptions concerning the reduction of the sulfur content in coal due to washing. By way of comparison, the Mitre study[4] estimates that known bituminous coal reserves remaining in 1968, assuming that all are to be crushed to a 3/8 inch top size and washed to the 90 percent yield point, are (in millions of equivalent tons) 9930 in northern Appalachia, 44840 in southern Appalachia, and 790 in the eastern Interior region.

Coal production in the United States in 1970 amounted to 611.5 million tons. The Hoffman Study[5] indicates that in 1969 the coal industry contemplated a growth rate of 7 percent per year through 1973. While that study applied the growth rate equally across all sulfur classes, such a procedure does not appear entirely reasonable. In order to test the adequacy of reserves in the light of air pollution control regulations and premium prices for low sulfur coal, it is more reasonable to apply the entire growth potential to low sulfur coal.

A 7 percent growth rate, given production of 611.5 million tons in 1970, implies coal production of 1687.3 million tons in 1985. In turn, this implies cumulative production from 1970 to the end of 1985 of 17,054.6 million tons. This includes coal of all ranks and is on a simple weight basis. However, on a sulfur adjusted basis, by 1985 known recoverable reserves would be insufficient by a total of 1.4 billion tons. Furthermore, cumulative production between 1970 and 1985 would amount to over 11 percent of the

Table 4

Low Sulfur Coal: Comparative Estimates of Resources and Recoverable Reserves in the $\leq 0.7$ Percent Category (Jan. 1, 1965).
($10^6$ Short Tons)

| | Conventional(1) | Standardized(2) | Standardized with Washing | | |
|---|---|---|---|---|---|
| | | | Pessimistic(3) | Average(4) | Optimistic(5) |
| Bituminous Coal | | | | | |
| Appalachian, North | 45 | 54 | 3360 | 3360 | 29004 |
| | 5 | 6 | 438 | 438 | 3774 |
| South | 37275 | 44730 | 44703 | 93960 | 93960 |
| | 4100 | 4920 | 4920 | 10332 | 10332 |
| Total | 37320 | 44784 | 48090 | 97320 | 122964 |
| | 4105 | 4926 | 5385 | 10770 | 14106 |
| Interior, East | 195 | 207 | | | |
| | 50 | 53 | | | |
| West | 250 | 265 | | | |
| | 20 | 21 | | | |
| Total | 445 | 472 | 472 | 2101 | 2101 |
| | 70 | 74 | 74 | 343 | 343 |
| Rockies, North | 6275 | 6526 | | | |
| | 690 | 718 | | | |
| South | 38940 | 42055 | | | |
| | 3895 | 4207 | | | |
| Total | 45215 | 48581 | 94910(6) | 94910(6) | 285469(6) |
| | 4585 | 4925 | 9557 | 9557 | 29761 |
| West Coast | 900 | 855 | | | |
| | 80 | 76 | | | |
| Bituminous Coal-Total | 83880 | 94692 | | | |
| | 8840 | 10001 | | | |

| | | | | | |
|---|---|---|---|---|---|
| Subbituminous Coal | | | | | |
| Rockies, North | 129665 | - | | | |
| | 14265 | - | | | |
| South | 52005 | 46329 | | | |
| | 5205 | 4632 | | | |
| Total | 181670 | 46329 | | | |
| | 19470 | 4632 | | | |
| West Coast | 3780 | - | | | |
| | 340 | - | | | |
| Subbituminous Coal-Total | 185450 | 46329 | | | |
| | 19810 | 4632 | | | |
| Lignite | 344620 | - | | | |
| | 37905 | - | | | |
| Anthracite | 12550 | 14056 | | | |
| | 1630 | 1826 | | | |
| Total-All Ranks | 626500 | 155077 | 155955(7) | 206881(7) | 423084(7) |
| | 68185 | 16459 | 16646 | 22300 | 45840 |

(1) Table 1, column 1.

(2) Table 2, column 1.

(3) Table 3, column 1.

(4) Table 3, column 2.

(5) Table 3, column 3.

(6) Includes bituminous, subbituminous and lignite. Comparable figures for these three ranks in this table are 571505 in column 1
61960
and 94910 in column 2.
9557

(7) Includes unwashed anthracite as a constant in all three estimates at 12550.
1630

Note: Standardized estimates are expressed in equivalent tons of 22.6 MMBtu/ton coal.

total known reserves in the ≤ 0.7 percent sulfur class on a sulfur adjusted basis. If coal policy is based on the conventional estimates found in Table 1 column 1, no such problem exists. Cumulative production from 1970 to 1985 would be less than known recoverable reserves by 51.1 billion tons and represents only 2.7 percent of known reserves in the ≤ 0.7 percent sulfur category.

Extending the comparison to the standardized Btu and washed coal bases found in Table 4 columns 2-5 does not significantly improve the prognosis. Known recoverable reserves of low sulfur coal are inadequate except for the average and optimistic estimates of sulfur reduction by washing.

## 3. Policy Options and Alternatives

Coal policy alternatives include conserving low sulfur coal, utilizing high sulfur coal and identifying new reserves. The first is short term, the latter are essentially long term solutions.

In the very short run of one or two years, properly characterized as a time of specific fuel shortages rather than an energy crisis, conservation goals suggest the possibility of end use controls for low sulfur coal. These would apply primarily to the export market and to the iron and steel industry. Transfers would be made from mines supplying these users to the public utility sector. Of the total exports of 70.9 million tons of bituminous coal in 1970, 75.8 percent, or 53.8 million tons of bituminous coal, was low sulfur metallurgical grade. Exports of a scarce resource are a matter of both economic and national security policy. On the national level, there is no apparent reason why coal exports cannot be treated in the same manner as

current oil exports are treated by Middle Eastern countries or as Canadian exports of oil and gas to the United States are treated. The restriction of exports has an adverse balance of payments effect on the United States. To the extent, however, that restriction of coal exports leads to relatively lower energy and steel costs in the U.S. compared to Europe or Japan, the adverse balance of payments may be mitigated.

The use of coal by the iron and steel industry is based primarily on the production of coke. At present prices, there can be little substitution for coke. The costs of changes to direct reduction of iron ores in a fluid bed reactor or by flash reduction are high, the technology is relatively new, and the time horizon for general industry application is a matter of several years.

Table 5 presents some data on the nonmarket production of bituminous coal from captive mines. These mines are typically owned by firms in the steel industry. Some are owned by electric utilities, still others by oil companies. To the extent that air pollution control standards and the use of low sulfur coal are deemed to outweigh private commercial consideration, such coal could be made available for sale on an end use control basis to the general market; in particular to public utilities. Such transfer, however, does not increase reserves. It merely allows a change in the time horizon of their use and increases their market availability.

Long term energy policy with respect to coal must center on the use of high sulfur coal. The simplest administrative solution for both our present problem and most future energy problems would be to remove or reduce EPA emission control regulations which lead to the restricted use of

Table 5

Nonmarket Production of Bituminous Coal, 1970
(000 Tons)

Production from Consumer Owned Captive Mines

| Industry | Amount | Percent |
|---|---|---|
| Steel | 65,372 | 10.8 |
| Electric Utility | 15,165 | 2.5 |
| Others | 8,149 | 1.4 |
| Total | 88,686 | 14.7 |
| Total Production | 602,932 (1) | 100.0 |

Production of Bituminous Coal Not Sold in the
Open Market, 1970, Selected States

| State | Total Production (2) | Production Not Sold in Open Market | Percent |
|---|---|---|---|
| Alabama | 20,560 | 7,896 | 38.4 |
| Illinois | 65,119 | 2,136 | 3.3 |
| Kentucky | 125,305 | 8,364 | 6.7 |
| Pennsylvania | 80,491 | 29,529 | 36.7 |
| West Virginia | 144,072 | 18,843 | 13.1 |

Source: National Coal Association, Bituminous Coal Data, 1971 edition, p. 15.

(1) NCA, *op. cit.*, p. 13.

(2) NCA, *op. cit.*, p. 18.

high sulfur coal. This is being accomplished, in part, by the delay in the implementation of secondary emission standards. Shifting from source point standards to air quality zone standards also permits the direct use of more high sulfur coal. The administrative confusion between short-term specific fuel shortages and long-term energy supplies plus the natural interest that utilities and others have in avoiding additional capital investment (which may not easily find its way into the rate or price structure) is the driving mechanism.

Preservation of air quality standards, while utilizing reserves of high sulfur coal, requires the desulfurization of the coal before, during or after combustion. Coal gasification and liquefication both offer a current means of desulfurizing high sulfur coal before combustion. However, both are energy conversion processes of less than 100 percent efficiency. For this type of conversion process to be useful it must be an energy upgrading process. That is, one in which an inferior form of energy is used as an input to produce a superior or more useable form of energy. In this sense both synthetic natural gas and liquefied coal are superior in use to coal itself. Both are low sulfur, easily and cheaply transported and stored, and both can be used in more applications than coal. Since the efficiency of these processes is not 100 percent, air pollution control requirements predicate a sacrifice of some high sulfur coal if any high sulfur coal is to be used at all. While there is obviously an energy cost to air pollution control due to gasification or liquefication, it should also be noted that this is the standard practice in the upgrading of fuels (for example, the desulfurization of residual oil and the production of gasoline from crude oil).

One of the major problems in the implementation of coal gasification and liquefication technology is the water requirement. A number of sites for these plants have been identified on the basis of adequate water supply. Some, however, may be too close to densely populated areas or are otherwise unacceptable. The water problem is not trivial. In coal gasification and liquefication, water is used as a process input, the source of the hydrogen which must be added to the carbon in coal. It is not simply used as a coolant and returned to its source. Given water problems, distance from major markets (which requires extensive pipelining), and available economically recoverable reserves, coal gasificiation and liquefication plants in the states of Illinois, Indiana and Ohio would appear to be economically superior to those in the Rockies.

Coal liqueficiation, used in Germany during World War II reportedly does not have a proven economically feasible technology. While the U.S. Navy has already run a destroyer on a coal-derived oil, this only proves technical feasibility on an acceptable scale.

Stack gas desulfurization removes the sulfur content of the coal after combustion. It offers one route for maintaining air quality standards while allowing the use of high sulfur coal. Additionally, the fuel sacrificed in this process is less than that for either gasification or liquefication. The energy penalty for stack gas scrubbers, including particulate removal, is reported to be between 4 and 8 percent as compared to about 25 percent for liquefication and gasification.[6]

The average sulfur content of coal used for electric power generation in the United States is about 2.5 percent. At least 90 percent of the sulfur in the fuel appears in

stack gases as sulfur oxides. As the minimum value of sulfur in coal that can be used as fuel without any controls decreases as the heating value decreases, when using a 1.5 percent sulfur coal, a scrubber which is 50 percent efficient with respect to sulfur oxide removal will satisfactorily meet current emission standards for a coal which contains 13,000 Btu's per pound or more. An 85 percent sulfur oxide removal efficiency is sufficient when burning 4 percent sulfur coal. Since the average sulfur content of coal used in power plants is about 2.5 percent, as little as 75 percent efficiency is required to insure compliance with current EPA new source emission standards.(7) Most new plants have done significantly better.

One of the major obstacles to the use of stack gas scrubbers by utilities, aside from the fact that their costs may not necessarily be permitted to be reflected in electricity rates contra the passing through of the premium for low sulfur coal, is the assertion by the utilities that they are not sufficiently reliable. It is desirable that this be put into some perspective. In their expansion plans many utilities are making a choice between nuclear plants and coal-fired plants with scrubbers. The environmental impact statements indicate that, with respect to reliability, a double standard is being used. The utilities appear willing to accept a demonstrably lower reliability with respect to nuclear plants than with respect to scrubbers. Even if one accepts the low estimates for scrubber availability, they are comparable to nuclear plants. Louis H. Roddis, Jr., President of Consolidated Edison of New York has said, "... most, if not all, of the economic studies that led utilities to go nuclear were based on assumed energy deliverability of 80 percent or more." He pointed out, however, that as of October 1, 1972, the average energy delivery or availability

of the 18 reactors that were operating in the United States was only 60.9 percent.[8] If it is assumed that new steam electric plants have an 80 percent availability and that atomic plants have a 60 percent availability, a combination of fossil fuel steam electric plants and their necessary stack gas scrubbers would require that the stack gas scrubber have an availability of no more than 75 percent in order that the joint probability equal the 60 percent availability factor apparently acceptable to the public utility industry with respect to new atomic energy plants.

Stack gas scrubbing, coal gasification and coal liquefication all tend to reduce the dependence of the electric utility industry on the derated estimates of low sulfur recoverable reserves of western coal. In fact, because in an electrostatic precipitator the electrical resistivity of dust particles is greater with low sulfur, stack gas scrubbing is more efficient if the coal is high rather than low sulfur and if the ash content is relatively low. There is therefore, less need for stripmining or coal development in the Rocky Mountain region. Nevertheless, if western coal is considered an alternative to these processes for electric power generation in the Interior and Appalachian regions, it is possible to make at least a ball park estimate of the amount of money that would be available for gasification, liquefication or scrubbing in order to be able to use local coals in the high sulfur categories.

Recently, Detroit Edison made a commitment of twenty-six years duration for the purchase of low sulfur low ash coal to be sent to an existing plant in St. Clare, Michigan, and to a new plant in that region which will be ready by 1980. The contract calls for a total coal shipment of over 1980 million tons; approaching 4 million tons per year in 1976 and rising

to 7 million tons per year for the period from 1981 to 2002. The value of the contract according to the seller is approximately $750 million. According to the buyer, the value of the contract for the twenty-six years is $1 billion for coal, plus $2 billion more for transport and storage.[9] It is this $2 billion which, over a twenty-six year period, must be considered available for alternate uses; in particular, for the purchase of liquefied or gasified coal from midwest and Appalachian sources or stack gas desulfurization. While it has been noted above that gasification and liquefication involve an energy loss due to processing, it should also be noted that the transportation cost for coal from Montana or Wyoming to Michigan involves an energy cost of 3-5 percent of the heat value of the coal involved. Risser reports that a 7 million ton coal contract, involving rail transport from Wyoming to Chicago, would require 750,000 barrels of diesel oil per year.[10] This cost is paid for, not in terms of relatively abundant coal, but in terms of diesel fuel oil.

## B. Coal Reserve Estimation

### 1. Statistical Estimation

There are many different coal "reserve" estimates. While the figures produced vary widely, they are not necessarily inconsistent. The differences are based primarily on the expected use of the data which predicates the bases on which the data are collected. It is important to be aware of some of the distinctions. Of principal interest is the difference between resources in the sense of physical existence and that portion of these resources that can be recovered economically at current prices with existing technology. These are called economically recoverable reserves. Both measures are stated in terms of tons. The difference between them is significant for policy purposes as only the latter are available for consumption in the present and near future. The former may become available after a longer period of time or may never be recovered.

The estimate of coal resources in the broadest physical sense is the resource base.(11) Coal mining areas which have been mapped and explored yield a resource estimate of 1.56 trillion tons. This is limited because not all areas have been thoroughly mapped and the estimate includes only those resources with less than a 3000 foot overburden. This estimate is subdivided into measured, indicated and inferred classes based on the reliability of the estimate. Inferred resource measures are based on geologic evidence alone. Measures of indicated resources are derived from both specific observations and geologic projections. Measured resources, properly called physical reserves to distinguish them from economically recoverable reserves, are the most reliable esti-

mates. These are based on data derived from outcroppings, trenches, mine workings and closely spaced drill holes.

Because of the limits of existing technology, resource estimates may be further limited to those lying beneath less than 1000 feet of overburden. These are further subdivided into thick, intermediate and thin coal seams. High rank coals, those with a high heat content such as anthracite, semianthracite and bituminous coal, are classified as lying in thick seams if the seam is thicker than 42 inches. Low rank coals, such as subbituminous coal and lignite are classified in thick seams only if the seam is more than 10 feet thick. Intermediate seams are 28-42 inches and 5-10 feet for high rank and low rank coals, respectively. Thin seams include only those from 14-28 inches or 2.5-5.0 feet thick. By restricting the depth of the overburden and classifying by seam thicknesses which differ by rank, a concept of economic classification is introduced. This is only implicit and is not meant to indicate economically recoverable reserves.

Measured and indicated coal resources covered by less than 1000 feet of overburden, lying in beds of all three thicknesses, amounted to 483.6 billion tons in 1970. Of this, 124.8 billion tons were classified as measured reserves. Alternatively, measured reserves and indicated resources lying in thick and intermediate beds or seams totaled 394.1 billion tons. Of this, 349.1 billion was mineable by underground methods. By eliminating the more expensively mined bituminous and subbituminous coal and lignite in beds of intermediate thickness, this total can be reduced to a physical reserve estimate of 209.2 billion tons. Assuming that 50 percent of this can be recovered at current prices by current mining techniques we have an estimate of 104.6 billion tons

of economically recoverable reserves underground. To this last can be added 45 billion tons of economically recoverable reserves accessible almost exclusively by stripmining.

The U.S. Geological Survey estimates identified recoverable coal resources in the United States at 200 billion tons lying in thick beds. At a somewhat higher cost of recovery an additional 190 billion tons can be added by including coal in beds of intermediate thickness. Estimates of identified submarginal resources, stated in terms of weight but essentially meaning those which cannot be economically recovered at current prices and/or with current mining techniques, are an additional 1200 billion tons. Finally, undiscovered coal resources, with an overburden of less than 3000 feet, are estimated to be an additional 1300 billion tons. A recovery factor of 50 percent of the coal in place is assumed.(12) The Bureau of Mines estimated coal resources in the United States, of all ranks, as of January 1, 1970, at 778,274 million short tons. This assumes a 50 percent recovery of the coal in place.(13) It is approximately one-half of the 1.56 trillion tons noted above but it is not a measure of economically recoverable reserves.

Table 6 indicates three additional estimates of coal and lignite reserves in the United States. The estimate by the Department of the Interior,(14) while it is reported to be recoverable reserves, is actually similar to the Bureau of Mines' estimate of coal resources noted above; it is a physical resource estimate. The two estimates from the Mitre Corporation study(15) are somewhat different. Known reserves (column 2) are in the resource context of the Bureau of Mines' estimates and include both known recoverable reserves and known marginal and submarginal resources. Column 3 represents a considerable effort to reduce the estimate of column 2 from

Table 6

Bituminous Coal and Lignite Reserves
Comparative Estimates
(Million Tons)

| | Department of the Interior(1) | Mitre Corporation(2) Known(3) | Recoverable(4) |
|---|---|---|---|
| Appalachia | 109581 | 216440 | 25875 |
| Interior | 178318 | 372627 | 72943 |
| Rocky Mountains | 228358 | 872445 | 94265 |
| West Coast (ex. Alaska) | 2617 | 5950 | 530 |
| Totals | 518874 | 1467462 | 193613 |

(1) Department of the Interior, United States Energy Fact Sheets by States and Regions, February 1973. Measured coal reserves (1/1/71) that are economically recoverable. The underground coal recovery factor is estimated to be 57 percent, the area stripmining recovery factor is 90 percent, and the contour stripmining recovery factor is estimated at 80 percent.

(2) L. Hoffman, Survey of Coal Availabilities by Sulfur Content, Report to the Environmental Protection Agency, The Mitre Corporation, MTR-6086, May 1972.

(3) Known reserves: recoverable, marginal and submarginal based on U.S. Geological Survey classifications.

(4) First order estimate of known recoverable reserves alone. U.S. Geological Survey classification is the basis. Recovery factors are: underground mines, 50 percent; stripmining in Appalachia and Interior regions, 60 percent; stripmining in the Rocky Mountain region, 80 percent.

a resource base to one of known recoverable reserves alone. The result is comparable with the 209.2 billion tons reported by the National Petroleum Council. In contrast, Hubert Risser(16) estimated that at the end of 1970, about 390 billion tons of coal were considered mineable with current technology, of which 200 billion tons could be produced at current costs and 190 billion tons at somewhat higher costs. If Risser's estimate of economically recoverable reserves is accepted, both the Mitre (192.6BT) and the National Petroleum Council estimates (149.6BT) can also be considered economically recoverable reserves. If the National Petroleum Council estimate is accepted, both the Mitre and Risser estimates may include elements of coal, unrecoverable at current prices.

The foregoing must be tempered by an understanding of the estimation of reserves and their classification. The commonplace consideration of production or output as dependent directly upon price is a simple statement of the supply curve. But, reserves are also a function of price. Estimates of resources and reserves are not ultimate figures, but are themselves dependent upon the sale price and costs of production ruling at the time the estimates were made. As coal prices rise, resource and reserve estimates of coal will also rise. This does not mean that additional recoverable reserves of low sulfur coal or any other particular type of coal will be found. However, it is probable that, as new coal reserves are found or developed, the low sulfur coal segment will be preferentially produced.

Increases in coal resources and recoverable reserves occur when previously undiscovered resources are discovered. This requires an active exploration program. Increases may also occur because resources, already known to be available,

move from the class of known reserves to the higher class of known recoverable reserves or from submarginal reserves to recoverable reserves. Price is the driving mechanism. The willingness to explore in the hope of finding something must be matched against the expense of the exploration. In the event that something is found it is rendered profitable and exploited because of the anticipated sale price. The movement of known reserves into the economically recoverable category is due to price increases making it profitable to increase the recovery factor in existing mines, to develop thinner beds and seams and to engage in secondary recovery.

As an example of possible resource and recoverable reserve additions due to exploration, it may be noted that it is probable that reserve estimates of coal in the Rocky Mountain areas are understated. Less is known about that region than is known, for example, about coal resources in the Appalachian region. The National Petroleum Council has argued that further mapping and exploration, especially in the western states, should result in substantial increases in the U.S. Geological Survey's estimates of coal reserves that can be mined with existing technology.(17) They show that the ratio of "unmapped and unexplored" coal resources to total resources is 73 percent in Wyoming, 41 percent in Montana and 34 percent in North Dakota. In the Midwest the ratio is 42 percent in Illinois and 39 percent in Indiana. In the East, the ratio is very much lower; 13 percent in Pennsylvania and zero percent in West Virginia.(18) Resource increases due to changes in the classification of resources are exemplified by the definitions of resources used by the U.S. Geological Survey.(19) All of the factors which contribute to their definition of a coal seam by resource class depend upon the cost of production and the sale price.

As low sulfur coal becomes a premium fuel, it is to be expected that economically recoverable reserves in this category will rise simply by redefinition. As prices rise, even thin beds and coal deposits heretofore considered inaccessible for shipment become economically much more interesting. The DeCarlo study, upon which much of the Mitre study was based, provided reserve estimates for January 1965. If prices were specifically considered, they would have been 1964 prices. Between 1964 and 1971 the average value of coal rose by 62 percent. It is more than likely that increases of this magnitude were sufficient to generate more economically recoverable reserves of coal by shifting from classes or categories of lower recoverability to those representing higher recoverability. As the low sulfur categories were already beginning to move to a premium, such reserve shifts were even more likely in these categories. Furthermore, in the face of premium prices for low sulfur coal and the growing demand for the product, it is very unlikely that the same mining recovery factors exist for low sulfur coal as for high sulfur coal.

Because of its currency, coverage and detail, some of the output of the Bureau of Mines' data file were examined. The data file has at least one inherent failing because it uses data from surface exposures, such as operating and abandoned mines, and extrapolates using varying degrees of geologic inference. This method results in an overall crude estimate of physical reserves suitable for mine use but not sufficiently accurate for an assessment of energy resources and optimization of their use. The reserve base includes some beds which are thinner or deeper than general criteria permit, but are currently being mined or could be mined commercially at this time. This last calls into question their entire scheme of resource classification.

Other elements which reduce the utility of the USBM data bank as a catalogue of resources and reserves include:

1. Thickness limits within a category are economically controlled and should be reduced uniformly to conform with state data sources in order to be inclusive of all measurable reserves.

2. Classification of reserves by the reliability of the data should differentiate between data based entirely on surface exposures, mining operations and their extrapolation; and those based also on reliable subsurface data. The former may be subject to review should legislation curtail or eliminate surface mining operations or should changing economics (technology) lengthen mine life. The latter is the only reliable measure of reserves that accounts for coal seam variability.

The USBM categories are complicated, overlapping, unrelated to costs and not functional with respect to national priorities. Their emphasis is not upon estimating economically recoverable reserves but physical reserves and resources.

For national policy purposes, the aim should be a data base categorized in such a way that movement between categories is only with respect to new geologic data. The subdivision of reserves into physical and economically recoverable categories would be based on current, state of the art, mining technology with respect to the geologic structures and habitat and with respect to coal prices. As in the petroleum industry, this would allow for shifts in recovery factors if, for example, secondary recovery becomes profitable or new

techniques remove a greater percentage of coal from the ground or out of preparation plants. Furthermore, on an economic basis, more attention could be paid to coal quality: Btu content, sulfur content, ash, moisture, etc.

The present system does not deal as effectively with physical and economically recoverable reserves as it does with the classification of resources. Yet it is the former that is important for our current and near future policies.

There is a need, through the Bureau of Mines, for the development of a systematic methodology for obtaining estimates of economically recoverable reserves from physical reserves and physical reserves from identified resources. This means close attention to prices and the evaluation of relevant state of the art technologies given the geophysical characteristics of the seam and habitat. This may require much more mine disclosure in the national interest.

Additionally, a significant amount of developmental drilling should be undertaken in order to not only firm up the estimates of the resources lying behind the reserves, but to estimate the coal qualities as well.

Illinois and Wyoming have been investigated as examples of states whose approach to coal reserve estimation provides some significant contrast. The differences are in part geological; e.g., the nature and occurrence of the coals; and, in part, economic. To date, it has not been necessary or profitable for Wyoming geologists to prove and measure reserves outside of presently working mines. In view of the low sulfur content and vast resources potentially available, it would be advantageous to have an accurate, consistently derived, physical and economically recoverable reserve estimate for Wyoming. Illinois coal estimates on the other hand,

may be considered nearly all reserves rather than a reserve-resource mixture.

The detailed examination of the reserve-resource estimating procedures used in each state can be found in Appendix D.

## 2. Illinois Coal

Illinois coal reserves have been mapped where they exist to a maximum of 1500 feet. In Illinois, underground coal mines extend only to depths of 800 feet.

The latest estimates of coal in the ground (physical reserves) for Illinois were published in January 1974, by the Illinois State Geological Survey. The new estimate is 148,172,540,000 tons.

Only oil pool areas, heavily drilled for oil and gas, have been excluded from the reserve estimates. In the classic study of coal reserves in Illinois the evaluation of mineability was based entirely upon the criterion of thickness, but it is generally conceded that surface features such as cities, towns, highways, railroads, etc., render coal unavailable for underground mining. To assume, however, that thickness is the only criteria determining mineability results in too large an estimate of recoverable coal. Several other factors such as mining method and economic factors are involved. The estimates include coals that are greater than 28 inches in thickness, if more than 150 feet deep, and greater than 18 inches if less than 150 feet deep. Thinner coals seams are not included in the estimates. An estimate of 1800 tons per acre foot of coal was used in calculating Illinois reserves. Though in some areas, 1770 tons per acre foot is probably more representative of Illinois coals.

In Illinois, the thickness limits used by the State Geological Survey are sufficient to cover all the reserves (as defined) because relatively little coal as thin as 18 inches has been mined. Further, although it is technologically possible, very little strip mining has as yet moved more than 100 feet of overburden. Some coal seams approximately 30 inches thick have been mined in small operations. Most sizable operations mine coals three to four feet thick, and, in large scale operations, the coal seams are generally even thicker. Currently no underground coal seams less than four feet thick are being mined. Therefore, there is an unspecified tonnage of coal, currently outside the measured limits, not included in the reserve-resource estimates. An important aspect of Illinois coal reserve data supplied by the Illinois State Geological Survey is the detail presented. The estimates would increase if the thickness limits were lowered, but they would not be altered as significantly by the elimination of strip mining as in those states where the entire measured reserves are in areas of surface exposure, in outcrop, or in operating or abandoned mines, e.g., Wyoming.

In Illinois a few areas remain for which sufficient information for reserves estimation is not available (e.g., the Pennsylvanian (age) boundary in western Illinois) yet the Illinois' estimates are probably the best there are and, at best, are probably still conservative.

Even when the data are good, gross discrepancies among reported estimates made by different organizations may occur. This is exemplified by a county by county comparison between estimates made by the Illinois State Geological Survey and the U.S. Bureau of Mines' estimates of the bituminous coal reserves of Illinois. According to the Survey, underground coal reserves are approximately 122,041.8 million tons.

According to the Bureau of Mines they are only 53,441.9 million tons. As estimated by the Bureau of Mines (IC8655), the underground coal reserve base does not include tonnages for coals less than 28 inches thick and at depths greater than 1000 feet. Those beds considered too deep, too thin, or in which the tonnages are in an inferred category strongly or weakly indicated reserves of ISGS) are not included in their estimates. Entire counties were omitted because the coals are strippable, too thin, too deep or inferred. Their estimates therefore exclude coals included in the ISGS estimates between 24-28 inches and depths greater than 1000 feet, but these few exceptions do not account for the large discrepancies between the estimates derived from the available data. Much more may be due to the inclusion, in the ISGS data, of coal which may not be mined due to surface features.

3. Wyoming

For Wyoming, Averitt (1973)[20] used the reserve estimate reported in Berryhill, et al (1950)[21] of original reserves of 121,553,850,000 short tons to determine his estimate for remaining reserves of 120,656 x $10^6$ (of which 12,705 x $10^3$ tons was bituminous coal and the rest, 196,951 x $10^6$ short tons is subbituminous) simply by subtracting production to date. For the purposes of his appraisal, all lignite was classified as subbituminous coal. No coal under an overburden greater than 3000 feet was included in the 1950 estimate. Averitt (1973) includes an unsupported 425,000 x $10^6$ short tons for total estimated hypothetical resources (USGS terminology) not found in the 1950 publication. This figure represents an estimate of resources present under an overburden of from 3000-6000 feet. These resources occur in unmapped and unexplored areas in known coal fields.

At best the Wyoming estimates are very conservative totals.[22] Recent work in reserve estimate revision in Wyoming coal fields has been published by G. B. Glass of the Wyoming Geological Survey. Glass' estimates of original coal resources of the Hanna Coal Field are revised from Berryhill et al (1950) to 3,918,590,000 tons ($\leq$3000 feet overburden). The remaining resource is calculated to be 3,828,169,616 tons, using an 80 percent recoverability factor for strip mine production to January 1, 1972.[23] Glass' estimate for the 0-1000 feet category (he termed it "a guess") was merely a percentage of the remaining resource as are his estimates of a strippable resource figure. However, the estimate is considered better (less conservative) than that given by the Bureau of Mines (IC8538) and, while recognized as "at best a crude approximation," is believed by Glass to be at least of the right order of magnitude.

Total strippable reserves of 23 billion tons were estimated for seven major Wyoming coal areas active in 1969 (USBM, 1972). Surface mining accounts for 100 percent of all the coal mined in Wyoming (G. B. Glass, 1974). The 1972 report by the Bureau of Mines (IC8538) summarized and interpreted information available to them on strippable coal in Wyoming. Cursory examinations were made of the coalfields and strip mines; and factors that would affect strip mining, particularly coal and overburden characteristics, were noted. Coal outcrop and reserve data were obtained from reports of the USGS. Firms engaged in exploration and acquisition of coal lands in Wyoming were consulted to obtain supplemental information. Obviously, Wyoming reserve base estimates would be reduced significantly by the curtailment of surface mining operations.

## C. Mine Productivity

If coal output is to increase in the face of recent difficulties in obtaining more young miners, mine productivity must increase. Even relatively modest rates of increase in required coal production cannot be met under existing conditions.

Productivity in underground mines increased steadily from 1960 until the passage of the 1969 Federal Coal Mine Health and Safety Act. Productivity increases ranged from 10.64 tons/man-day in 1960 to 14.00 tons/man-day in 1965, and reached 15.61 tons/man-day in 1969, before dropping drastically because of the new restrictions. Although tons/man-day increased each year from 1960 to 1969, the rate of increase declined considerably in the later years; while productivity increased substantially over the decade, it appeared to be leveling out. Fortunately, the decrease in productivity since 1969 has also all but leveled off.

In the past, much of the increase in underground mine productivity could be attributed to increased mechanization. By 1970, however, mining had become almost fully mechanized, although not automated. In 1960, 86.3 percent of all coal produced was mechanically loaded, in 1965 it was 89.2 percent, and by 1969 the percentage was up to 96.6 percent. While some increase in productivity can be attributed to this, the effect since 1965 has been slight. Most gains in this period must be attributed to improvements in machinery or techniques.

There are three basic mining methods currently in use: conventional (using room and pillar layouts), continuous (also using room and pillar layouts), and longwall. As long-

walling and shortwalling have only recently been extensively used in the United States, and then only under adverse conditions, their productivity rates are difficult to determine. For example, in 1968, 1.8 percent of all underground production was from longwalls. By 1973, this had increased to only 2.6 percent. It is reasonable to expect that longwall productivity will increase relative to other types of mining as longwalling becomes more widely used. There may be an indication of this in that longwall losses due to the 1969 Safety Act were less than for other types of mining.[24]

It is difficult to determine the relative productivities of continuous and conventional mining. From 1971 until 1973, productivity for loading machines dropped from 11.00 tons/man-day to 9.75 tons/man-day while that for continuous miners dropped from 13.00 to 12.25.[25] The relative decreases agree with the results of Straton's 1972 study in which it was found that continuous mining suffered less from the new regulations.[26]

Developments in haulage away from the mines have also increased productivity. Partly because of tramming time between faces and partly because of inefficient hauling, continuous miners operate less than 30 percent of the time, although their instantaneous mining rates may be 15 tons/minute.[27] This indicates that, at least under favorable conditions, continuous miner productivity could be considerably increased. It should be noted that while the percentage of coal mined by continuous miners increased less than 4 percent between 1966 and 1969, it increased nearly 10 percent to 59.3 percent from 1969 to 1973.

Continuous miners are used only two to three hours per shift, because of rising costs of roof control, larger machines will not be usable, and no more breakthroughs such

as roof bolting are in sight. Because of this, new gains in productivity must come from the operation of equipment that moves the mined coal away from the face to some point where haulage capacity is not limited.[28] The way this is done is strongly connected with the mining system.

In conventional mining, the coal must be loaded from the floor. It can be loaded directly onto a conveyor or into shuttle cars which discharge into mine cars or onto a more permanent conveyor. The continuous miner can load directly onto a conveyor, into a shuttle or surge car, or onto the ground. Longwall mining is best suited for continuous haulage because, by the nature of the system, coal is placed directly onto a stationary conveyor after being taken from the face.

The difficulties in connecting a conveyor to a loading machine or continuous miner have only recently been partially resolved. Herman[29] describes an all-conveyor sytem in a mine in Illinois. In this sytem, a continuous miner discharges into a surge car which unloads onto a bridge conveyor which in turn is connected to a Serpentix conveyor. He claims an increase in coal production per shift from 775 tons to 1075 tons. Garzes[30] reports on the replacement of a shuttle car system with a conveyor system because the mine floor consisted of fire clay which softens and becomes impassable to shuttle cars when water is present. He estimated production potential to be 30 percent higher with the conveyor system. He also remarks that conveyor use has been extensive in seams under 40 inches thick but that their use in thick seams has been declining. The advantages of shuttle cars also decreases as the distance they must travel increases.

## D. Legal Aspects of Coal Mining and Utilization

Appendix D contains four short analyses of the federal laws relating to coal mining and utilization. These include the availability of public land for coal mining, NEPA, the Clean Air Act and the Federal Water Pollution Control Act. Together these, along with their interpretation and administration, set the bounds to the development of coal. With tax and subsidy policy, it is changes in these acts and regulations that are the proximate means by which the federal government can alter coal reserves and production.

## E. Publication and Utilization

Over 200 copies of M. Rieber, Low Sulfur Coal: A Revision of Reserve and Supply Estimates, CAC Document No. 88, Center for Advanced Computation, University of Illinois at Urbana-Champaign, (NTIS P.B. 235-464), have been sent on request to individuals in government and industry. Additional copies have been sent through NTIS. It has been used, by both sides, in the Northern Great Plains Study. On the basis of this work, a request has been received from the Division of Coal, Bureau of Mines, to revise The Reserve Base of Bituminous Coal and Anthracite for Underground Mining in the Eastern United States, (IC8655), and the forthcoming companion volume on the western U.S., to a comparable Btu sulfur adjusted basis. A revised version of this study has been accepted for publication in the Journal of Environmental Economics and Management.

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## SECTION IV: COAL TRANSPORTATION

The lack of handling flexibility is one of the two drawbacks in the use of coal. It leads to relatively low productivity in mining and high cost in distribution. The emphasis here is on the costs of distribution rather than on the prices charged. The latter often reflects the lack of competition in coal haulage and, therefore, may include large elements of monopoly profit or economic rent. Additionally, for policy purposes, it is cost comparisons that are important with respect to the efficient allocation of scarce resources.

The following analysis includes unit trains, coal slurry pipelines and high pressure pneumatic pipelines. This last has been included, even though it has not yet reached the commercial stage of the first two because, given the enormous haulage requirements forecast for the near future, reasonable alternatives in the developmental stage are important.

Unit trains are used as the standard for comparison. An analysis and validation of their costs are presented in Appendix E, John A. Ferguson, "Unit Train Transportation of Coal." Comparisons and analysis of unit trains, slurry pipelines and high pressure pneumatic pipelines are contained in Appendix F. While the analyses and data validation are pragmatically directed towards cost minimization and system optimization, where theoretical solutions were necessary to further the practical work and evaluations, these were undertaken. These may also be found in Appendix F. They include: with respect to slurry pipelines--

S. L. Soo, "Equation of Motion of Solid Particle Suspended in a Fluid,' The Physics of Fluids, Vol. 18, No. 2, February 1975;

and with respect to pneumatic pipelines--

S. L. Soo, "Diffusivity of Spherical Particles in Dilute Suspensions," paper to be presented at the Symposium on Two Phase Flow, 15th National Heat Transfer Conference, San Francisco, August 10-13, 1975;

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Slurry pipelines and unit trains are directly competitive alternatives. A long distance pneumatic pipeline may be competitive with either one. A short distance pneumatic pipeline could be used as the basis of a gathering or distribution system for rail or barge shipments. It is not directly compatible for use with a slurry line because of the wetness of the coal particles coming from the latter.

## A. Summary and Conclusions

Our findings confirm those made elsewhere that, when new railroad is to be built (even if only 40 percent of the total distance), a slurry pipeline may have a cost advantage (cents/ton-mile) of as much as two to one. However, water requirements and the results of a possible line break or power loss are still unsolved environmental impact problems. Where roadbed is already available, even if the most elaborate upgrading is required to sustain a minimum loaded train speed of 50 mph, the resultant transporation cost is only one-half that of a new slurry pipeline. This result, together with the availability of the rail for other types of shipment and a further decrease in total coal transport costs if the rail

is served by a pneumatic pipeline system for gathering and distribution, rules out replacing existing railroad by slurry pipelines. Where railroad is nonexistent, and for long distances, a pneumatic pipeline will become competitive with a slurry pipeline.

A cost distribution shows that the slurry pipeline is capital intensive while a railroad (upgraded to 50 mph loaded) remains skilled labor intensive. For example, railroad equipment utilizes one-half of the steel tonnage of a slurry pipeline. Furthermore, the building of elements of a rail system is labor intensive and, therefore, contributes to employment in the years to come.

Abandoning railroads in favor of a slurry pipeline, such as the one proposed for shipment from Wyoming to Arkansas, would be a wasteful policy error. Our recommendations include identification of coal shipping railroads for upgrading, and federal expenditures to study the alternative indirect economic and social impacts.

Among the options for coal transportation, existing technology offers the choice of rail (unit trains) and slurry pipelines. Pneumatic pipelines offer another option [1]*; however, this technology for the shipment of comparable tonnage is presently incomplete and is more suitable for programs in the near future. Among the presently available options are new slurry pipelines and new rails or upgrading existing rails in various degress for unit train shipment.

National coal shipments were 0.63 billion tons per year (bty) in 1947, fell to 0.45 bty in the late 1960's, and increased again to 0.63 bty in 1974. The production estimate

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*Numbers in brackets refer to entries in references.

for 1985 is 1.2 to 1.5 bty [2]. The ability to triple the amount of coal shipped must be found. An estimated capital outlay of $21 billion by 1985 will be required. The accuracy of the estimates are dependent on the logistics of supply and the trend of technology. The tripling is not expected to be uniform; for example, coal gasification might take 30 to 40 percent of the coal produced, and regional concentration is expected. Alternatively, the estimated 50-50 distribution of surface and underground coal production might be altered [2]. Much of the currently planned eastward shipment of low sulfur western coal will be modified significantly by any gasification processes which can successfully handle high sulfur Illinois coal. Moreover, any predictions should include estimates of technological evolutions.

## B. Unit Trains

A data base of unit train costs has been developed for comparison with other coal transport options. These costs are significant because unit train tariffs (prices) charged by railroad lines do not necessarily reflect the actual costs of unit train shipments. This is especially true for large shipments. A computer model for unit train component costs developed by Ferguson [4] was used to calculate unit train costs.

### 1. Comparison and Justification of Model

To test the accuracy of the computer model, it was used to compute costs for current unit train operation. In comparison with one particular unit train contract (see Table 1), an average rate of 0.68¢/ton-mile is in line with a cost of 0.52¢/ton-mile based on our computer modeling. The latter

cost is for one million tons of coal per year using the average mileage of a Burlington-Northern unit train over a 1,050 mile route. However, when looking at the total Burlington-Northern unit train system from southern Montana and northern Wyoming, the rate of 0.68¢/ton-mile is over three times the calculated cost of 0.18¢/ton-mile based on 1,252 total train miles, and 16.5 million net tons per year. The tonnage used in the model of Burlington-Northern unit trains is the total from a chart of "Western Volume Bituminous Coal Rates" [6]. The mileage is from an average, weighted according to the annual tonnages. Thus, when comparing costs, it is found that railroad rates are in line with the model costs when individual routes are compared, e.g., from one mine to a particular station. This can be seen in Figure 1.

In Figure 1, small capacity unit trains were modeled for 0.5 to 1.5 million tons per year making trips of 100 to 600 miles to represent single contracts with a mine for coal shipment. However, when comparing the model's costs with a total railroad unit train route, where several mines in an area are served by the unit trains of a particular company to several destinations in an area, the model costs are much lower because of efficient train use and lower predicted road maintenance per ton-mile. This leads to the conclusion that unit train rates do not reflect the cost when the whole system is taken into account. This may occur because, often one railroad company is the only access to the mine or power plant, i.e., a monoploy rent is charged.

## 2. Analysis of the Unit Train Model

The following parameters are introduced to establish a rational basis for determining the statistical average for

Table 1

Model of Burlington-Northern
Unit Trains and Comparative Costs [6]

| | Unit Train Model Costs (million dollars) $16.5\times10^6$ tons/yr. | Costs (percent) | 1973 Railroad Costs* (percent) | |
|---|---|---|---|---|
| Labor | 14.2 | 45.0 | 55.5 | |
| Cars and Locomotives | 2.0 | 6.4 | 6.7 | |
| Fuel | 7.9 | 25.2 | 4.0 | |
| Depreciation | 2.7 | 8.6 | 5.6 | |
| Tax | 1.2 | 3.8 | 3.7 | |
| Supplies | 3.5 | 11.0 | 16.7 | |
| | | | 2.0 | (insurance) |
| | | | 5.8 | (income) |
| Totals | 31.5 | 100.0 | 100.0 | |

---

Operating Conditions:

16,500,000 net tons per year
1,050 average one-way miles
1,252 total track miles

0.682¢/ton-mile charged (average rate), 1974
0.182¢/ton-mile computer calculated average cost

Note: (0.520¢/ton-mile computer calculated cost for 1,000,000 net tons per year)

* Economics and Finance Department of Association of American Railroads, Yearbook of Railroad Facts, Washington, D.C., 1974, p. 11.

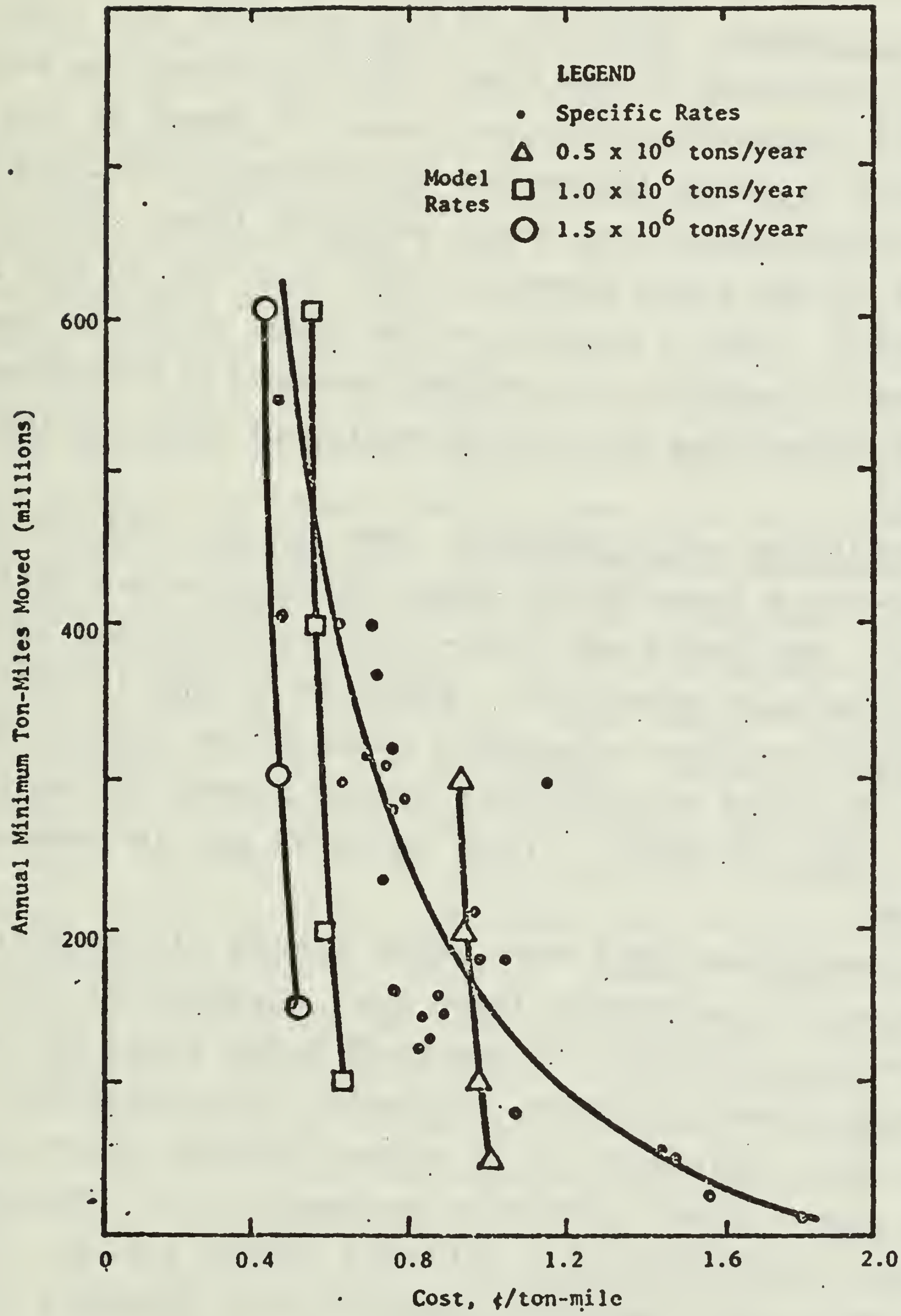


Figure 1. Representative Unit Train Rates for Eastern and Midwestern Movement [4] Compared with Model Unit Train Rates

cost of unit train shipment of coal and the desirability of railroad upgrading or rail building.

<u>Speed of Trains</u>: Fifty to 60 mph means 50 mph train speed at full load and 60 mph speed for returning the empty train. This is taken as the upper range of speed of the unit train, leading to large locomotive horsepower, significantly improved road condition, but short shipping time. Thirty to 60 mph means 30 mph train speed at full load and 60 mph for the empty train. This is taken as the lower economic speed of a unit train, calling for reduced locomotive horsepower but longer running time and not as stringent road condition requirements.

<u>Rail Condition and Upgrading</u>: New track, right-of-way, and road bed--this description means building a new railroad from scratch. New rails and ties--the existing road is upgraded to "like new" condition. Fifty to 60 mph in this case represents the best upgrading of existing rails. Track upgrading--the level of upgrading is the lowest degree of improvement that is useful. Only 30 to 60 mph is considered in this case.

It is recognized that much lower speeds of operation of unit trains are in existence (each coal shipment of 4,500 tons from Perry, Illinois, to the Wood River Plant of the Illinois Power Plant in Alton, Illinois, is an overnight trip of 12 hours for a distance of 75 miles; however these should be special cases; their operating parameters are not applicable to the formulation of a national energy policy. The basic parameters for comparing costs of coal shipment are dollars per ton for comparing various means of shipment between two points and cents/ton-mile as an elementary unit for comparing different routes of shipment. The dollar per $10^9$ Btu/mile parameter is useful when the comparison includes

coals of different heating values (12,000 Btu/lb for Illinois coal and 8,000 Btu/lb for Wyoming coal).

Rather than the deluge of data made possible by the computer, a sample of the most pertinent data is presented graphically (Figures 2, 3, and 4) so that trends may be readily seen. Figure 2 shows the constant rate of increase in cost (cents/ton-mile) when basic construction costs increase. Costs of shipment have a slow rate of increase when construction costs multiply with minimal track upgrade or new ties and rails but the rate is steep for new roadbed. Figure 3 shows the decrease of costs with increased net tonnage over a 400-mile route. It shows that at less than 10 million net tons per year, only minimal upgrade is economic while above that, a more thorough upgrading can be sustained. Figure 4 shows the decrease in cost per ton-mile when one-way trip mileage of a route is increased. Over 600 miles, there is little decrease in cost per ton-mile. Figure 5 shows the unit train route which could be used to supply gasification plants at Pine Bluff or Fort Smith, Arkansas [6]; Houston, Texas [8]; or Chicago, Illinois [10]. The cost per ton for shipment via these routes are given in Table 2. Table 2 shows the unit train costs for shipping one ton of coal from the mine to the point of delivery based on $25 \times 10^6$ tons per year. Different degrees of upgrading and different routes of various distances are shown. The data show the economy of upgrading the existing railroad to the best form (50 to 60 mph). These routes are used for comparison with the proposed slurry pipeline shipment from Wyoming to Arkansas [9] and from Colorado to Texas [10].

Table 3 shows costs and resources for unit train transportation for one set of conditions given in detail. These conditions apply to the Wyoming-Chicago or Colorado-Texas

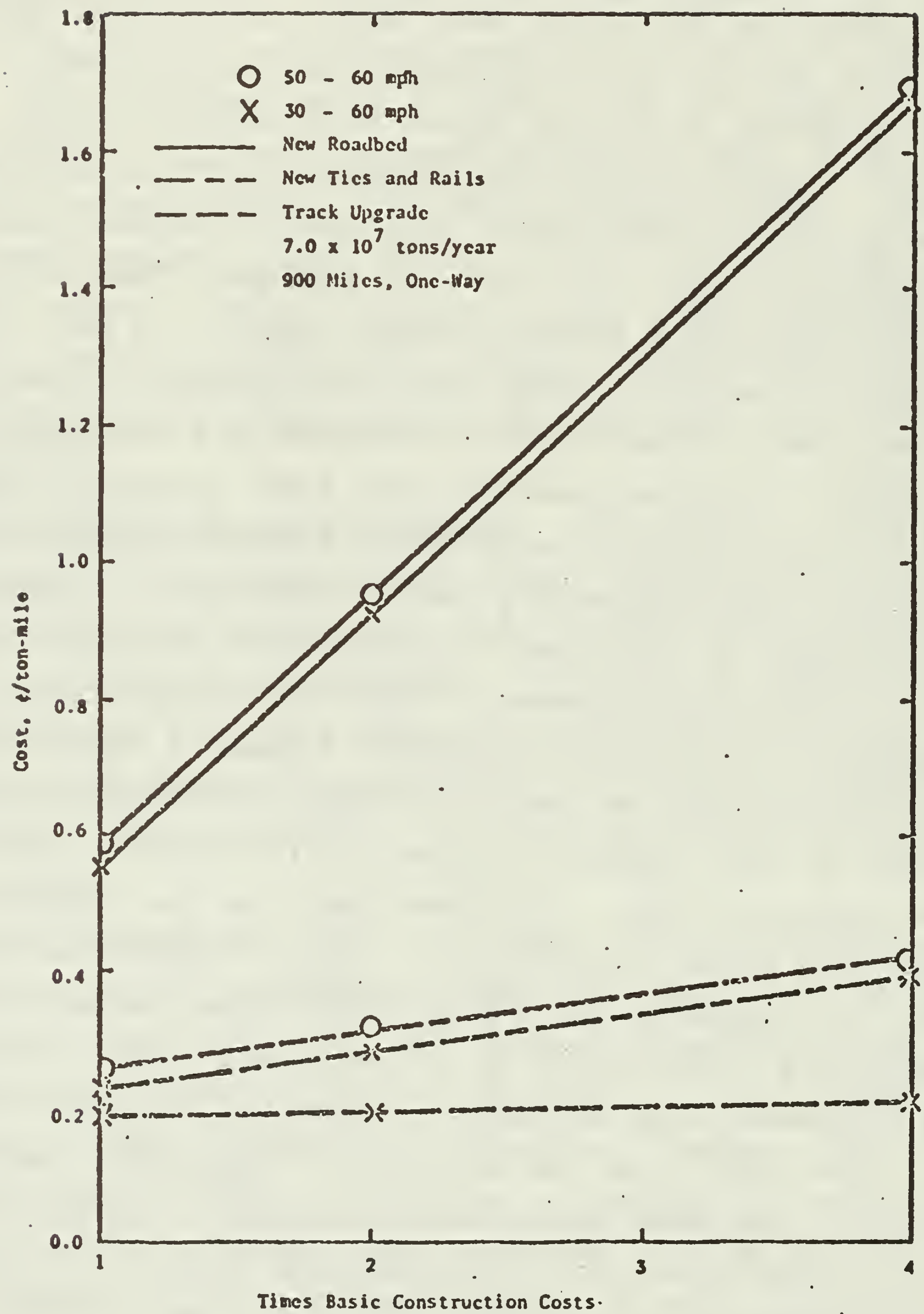


Figure 2. Increase of Rates with Multiplication of Construction Costs

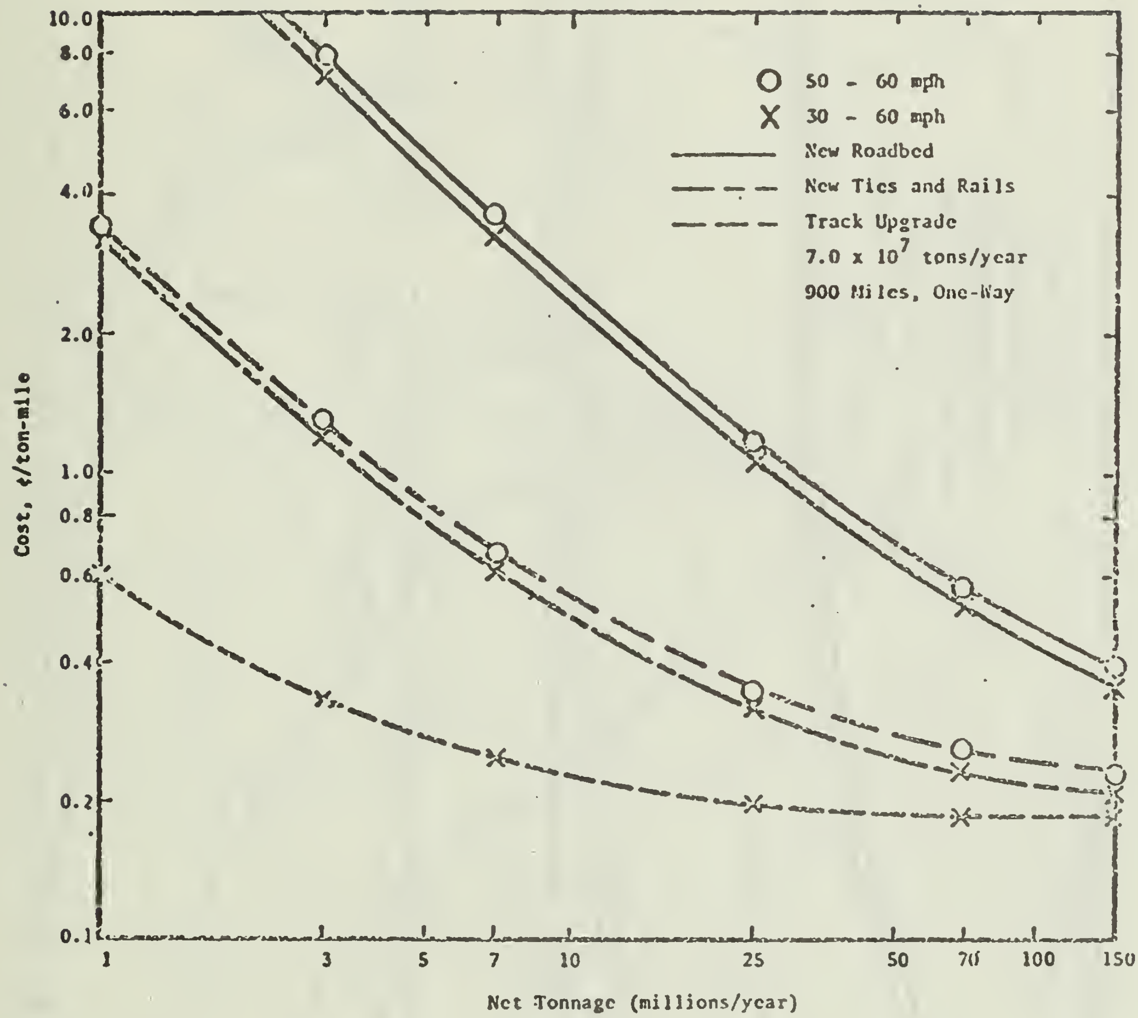


Figure 3. Decrease in Rates with Increase in Net Tonnage

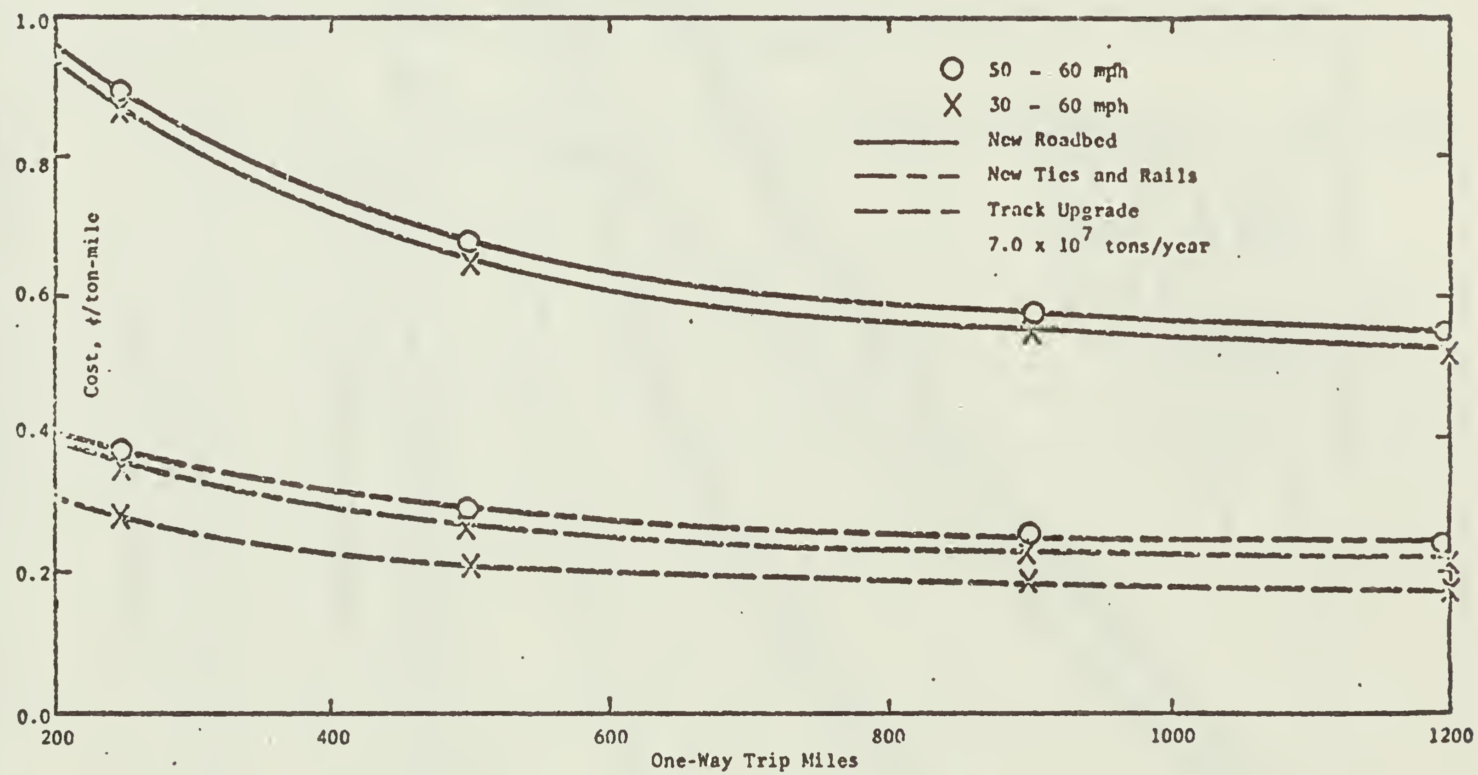


Figure 4. Decrease of Costs per Ton-Mile with Increase of One-Way Trip Mileage

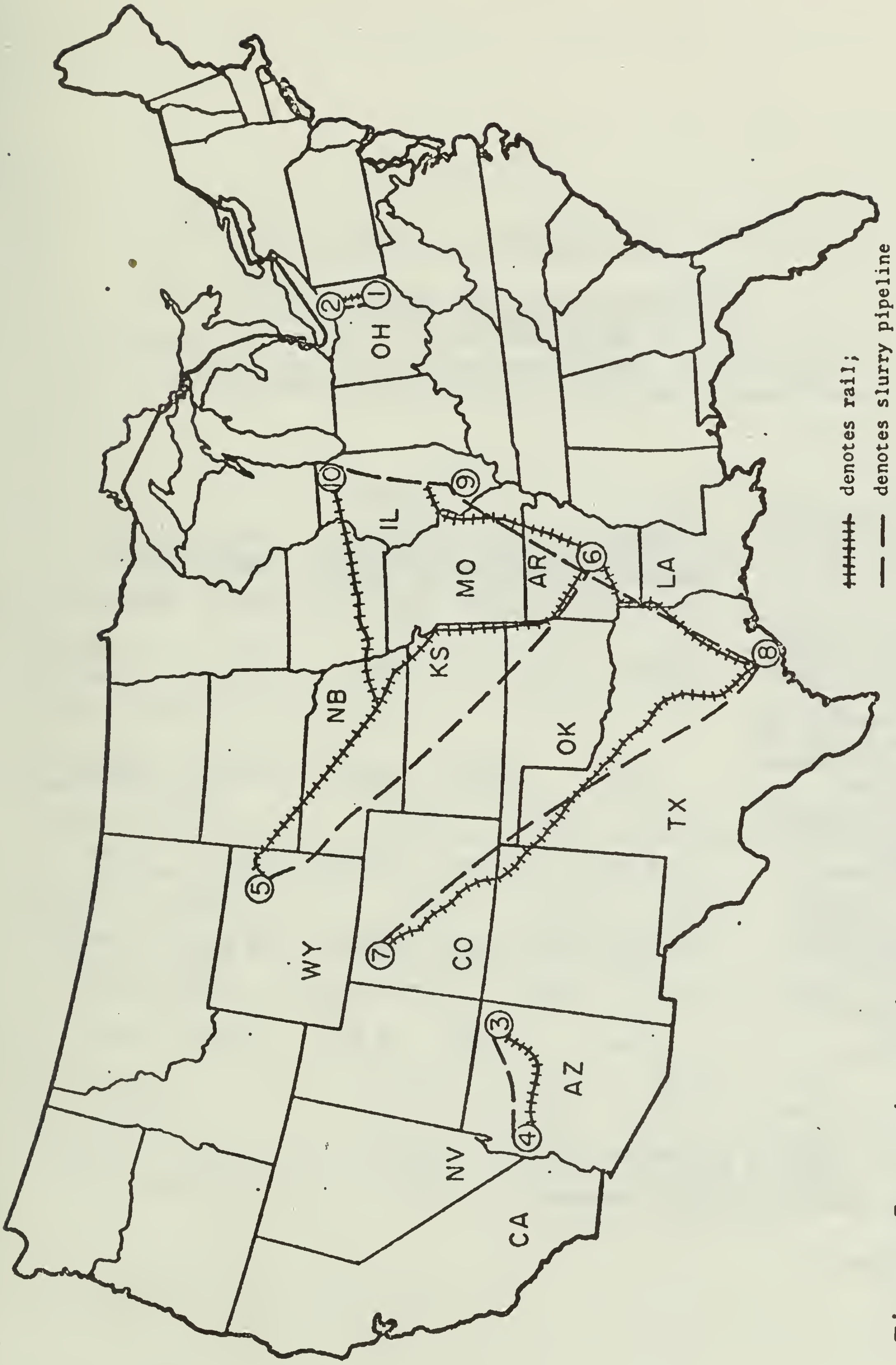


Figure 5. Unit Train and Slurry Pipeline Routes

Table 2

Unit Train Shipment Costs
(Dollars/Ton)
$25x10^6$ tons/year
($4x10^{14}$ Btu western coal or $6x10^{14}$ Btu Illinois coal)

| Route* | Minimal Track Upgrading 30 - 60** | New Rails and Ties 30 - 60 | New Rails and Ties 50 - 60 | New Tracks and Right-of-Way 30 - 60 | New Tracks and Right-of-Way 50 - 60 |
|---|---|---|---|---|---|
| (9)-(10) S. Illinois to Chicago 250 mi. | 0.72 | 1.18 | 1.26 | 4.41 | 4.48 |
| (5)-(10) Wyoming to Chicago or (7)-(8) Colorado to Texas 1,200 miles | 2.41 | 3.80 | 3.92 | 13.50 | 13.62 |
| (5)-(6) Wyoming to Arkansas 1,100 miles | 2.22 | 3.52 | 3.64 | 12.54 | 12.66 |
| (9)-(6) Illinois to Arkansas 500 miles | 1.19 | 1.90 | 1.96 | 6.80 | 6.89 |
| (9)-(8) Illinois to Texas 900 miles | 1.87 | 2.95 | 3.08 | 10.65 | 10.73 |

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* Refer to Figure 5 for routes.

** 30 mph loaded and 60 mph unloaded.

Table 3

Costs and Resources for Unit Train Transportation
(Costs in Million Dollars)

$25x10^6$ tons/year (22.7 metric tons/year)
1,200 miles one-way (1,900 kilometers)
Wyoming to Chicago (5)-(10) or Colorado to Texas (7)-(8)
1,424 miles total double tracks (2,290 kilometers)

| | Minimal Track Upgrading | New Rails and Ties | | New Tracks and Right-of-Way | |
|---|---|---|---|---|---|
| | 30 - 60* | 30 - 60 | 50 - 60 | 30 - 60 | 50 - 60 |
| CAPITAL COSTS: | | | | | |
| Roadbed | 43 | 320 | 320 | 2,250 | 2,250 |
| Equipment | 74 | 74 | 90 | 74 | 90 |
| Total Capital Costs | 117 | 394 | 410 | 2,324 | 2,340 |
| ANNUAL FIXED CHARGE ON DEBT: | | | | | |
| Average Rate Base | 58.5 | 187.0 | 205.0 | 1,162.0 | 1,170.0 |
| Debt Retirement (13.4%) | 7.8 | 25.1 | 27.5 | 155.8 | 156.8 |
| Federal Tax (28%) | 2.2 | 7.4 | 7.7 | 43.6 | 43.8 |
| Depreciation (25 yrs) | 4.7 | 15.8 | 16.4 | 92.9 | 93.5 |
| Total Annual Fixed Charge on Debt | 14.7 | 48.3 | 51.6 | 292.3 | 294.2 |
| OPERATING COSTS: | | | | | |
| Fuel Costs | 13.7 | 13.7 | 15.2 | 13.7 | 15.2 |
| Labor Costs | 27. | 27. | 27. | 27. | 27. |
| Supplies Costs | 6.6 | 6.6 | 6.6 | 6.6 | 6.6 |
| Total Operating Cost | 47.3 | 47.3 | 48.8 | 47.3 | 48.8 |

(continued)

* 30 mph loaded and 60 mph unloaded.

Table 3 Continued

| | Minimal Track Upgrading | New Rails and Ties | | New Tracks and Right-of-Way | |
|---|---|---|---|---|---|
| | 30 - 60 | 30 - 60 | 50 - 60 | 30 - 60 | 50 - 60 |
| UNIT COSTS: | | | | | |
| Dollars/ton | 2.48 | 3.82 | 4.02 | 13.58 | 13.72 |
| Dollars/metric ton | (2.66) | (4.20) | (4.42) | (14.90) | (15.00) |
| Dollars/ton-mile | 0.0020 | 0.0032 | 0.0033 | 0.0113 | 0.0114 |
| Dollars/metric ton-km | (0.0014) | (0.0022) | (0.0023) | (0.0077) | (0.0078) |
| ENERGY REQUIREMENTS: | | | | | |
| Locomotive (hp) | 300,000 | 300,000 | 530,000 | 300,000 | 530,000 |
| Million Barrels Fuel Oil | 1.60 | 1.60 | 1.80 | 1.60 | 1.80 |
| (% energy delivered) | (2.20) | (2.20) | (2.64) | (2.20) | (2.64) |
| EMPLOYMENT: | | | | | |
| Capital/Worker | .065 | .220 | .227 | 1.29 | 1.30 |
| Number of Jobs* (@ $15,000/yr) | 1,800 | 1,800 | 1,800 | 1,800 | 1,800 |

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* Figures do not include initial labor for upgrading (see Table 5) or jobs during the construction stage.

routes. Costs vary according to the amount of upgrading specified.

Table 4 shows costs and resources for unit trains operating via selected routes. The upgrading is to the extent of new rails and ties (best upgrading of existing rail). The costs and resources are given in detail. Low cost is achieved with a larger proportion of labor to material and energy than in the case of a slurry pipeline.

At the present time, there are unquantifiable costs for strikes and insurance. These may need to be added. Also, there may be added costs for road overpasses and crossings because at $70 \times 10^6$ tons of coal per year, a train would pass by a given point every 40 minutes. These overpasses or underpasses, which cost from $400,000 up, are shared by the railroad and highway with the former usually paying 10 to 20 percent [11].

### 3. Resources Used by Unit Trains

The resources required for a 1,200-mile (1,920 km) route from Wyoming to Arkansas, hauling 25 million tons (21.8 million metric tons) of coal per year, are given in Tables 3 and 4 along with the resources required for other potential routes.

Rail is one of the most efficient sources of transportation. It requires about 1.6 million barrels of diesel fuel per year at a 30 mph hauling speed, or up to 1.8 million barrels at 50 mph, and the coal hauled produces 4 to $6 \times 10^{14}$ Btu while the fuel oil could produce $1 \times 10^{13}$ Btu representing 2 percent of the energy. In the long run, however, diesel locomotives will probably be replaced by large horsepower gas turbine locomotives fueled by methanol produced from coal gasification products.

Table 4

Costs and Resources for Unit Trains
(Costs in Million Dollars)
($25x10^6$ tons/year or $22.7x10^6$ metric tons/year
New Rails and Ties
50 mph (80.5 kmph) loaded and 60 mph (96.5 kmph) unloaded

| | Routes (from Figure 5)* | | | | |
|---|---|---|---|---|---|
| | (5)-(10) (7)-(8) | (5)-(6) | (9)-(8) | (9)-(6) | (9)-(10) |
| Miles one-way | 1,200 | 1,100 | 900 | 500 | 250 |
| (Kilometers one-way) | (1,930) | (1,770) | (1,450) | (804) | (402) |
| Miles total double track | 1,424 | 1,324 | 1,124 | 724 | 474 |
| (Kilometers total dbl track) | (2,290) | (2,130) | (1,810) | (1,160) | (762) |
| CAPITAL COSTS: | | | | | |
| Roadbed | 320 | 298 | 253 | 163 | 107 |
| Equipment | 90 | 83 | 72 | 50 | 36 |
| Total Capital Costs | 410 | 381 | 325 | 213 | 143 |
| AVERAGE FIXED CHARGE ON DEBT: | | | | | |
| Average Rate Base | 205.0 | 190.5 | 162.5 | 106.5 | 71.5 |
| Debt Retirement (0.134) | 27.5 | 25.5 | 21.8 | 14.3 | 9.6 |
| Federal Tax (28%) | 7.7 | 7.1 | 6.1 | 4.0 | 2.7 |
| Depreciation (25 yrs) | 16.4 | 15.2 | 13.0 | 8.5 | 5.6 |
| Total Average Fixed Charge on Debt | 51.6 | 47.8 | 40.9 | 26.8 | 17.9 |
| OPERATING COSTS: | | | | | |
| Fuel Costs | 15.2 | 13.9 | 11.4 | 6.3 | 3.2 |
| Labor Costs | 27.0 | 23.5 | 19.8 | 12.6 | 8.4 |
| Supply Costs | 6.6 | 5.8 | 4.9 | 3.1 | 2.1 |
| Total Operating Costs | 48.8 | 42.7 | 36.1 | 22.0 | 13.7 |
| TOTAL ANNUAL COST | 100.4 | 90.5 | 77.0 | 48.8 | 31.6 |

(continued)

Table 4 Continued

| | Routes (from Figure 5)* | | | | |
|---|---|---|---|---|---|
| | (5)-(10) (7)-(8) | (5)-(6) | (9)-(8) | (9)-(6) | (9)-(10) |
| **UNIT COSTS:** | | | | | |
| Dollars/ton (Dollars/metric ton) | 4.02 (4.32) | 3.62 (4.01) | 3.08 (3.40) | 1.95 (2.16) | 1.26 (1.39) |
| Dollars/ton-mile (Dollars/metric ton-km) | 0.0033 (0.0023) | 0.0033 (0.0023) | 0.0034 (0.0024) | 0.0039 (0.0027) | 0.0050 (0.0034) |
| Dollars/$10^9$ Btu-mile** (Dollars/$10^{12}$ Joule-km) | 0.206 (0.122) | 0.206 (0.122) | 0.142 (0.084) | 0.162 (0.096) | 0.213 (0.126) |
| **ENERGY REQUIREMENTS:** | | | | | |
| Locomotive (hp) | 530,000 | 450,000 | 417,000 | 245,000 | 175,000 |
| Million Barrels Fuel (% energy delivered) | 1.80 (2.64) | 1.65 (2.27) | 1.30 (1.54) | 0.75 (0.79) | 0.40 (0.35) |
| Steel Required for 25 years in tons (and metric tons) | | | | | |
| For Locomotive | 75,000 (68,000) | 70,000 (63,500) | 60,000 (54,500) | 40,000 (36,000) | 25,000 (23,000) |
| For Rails | 550,000 (500,000) | 510,000 (460,000) | 435,000 (395,000) | 280,000 (254,000) | 185,000 (170,000) |
| **EMPLOYMENT:** | | | | | |
| Capital/Worker | 0.227 | 0.243 | 0.246 | 0.254 | 0.260 |
| Number of Jobs (@ $15,000/yr) | 1,800 | 1,570 | 1,320 | 840 | 560 |
| Jobs in Rail and Train Production | 310 | 290 | 245 | 160 | 90 |
| Total Jobs | 2,110 | 1,860 | 1,565 | 1,000 | 650 |

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* (5)-(10) is Wyoming to Chicago
(7)-(8) is Colorado to Texas
(5)-(6) is Wyoming to Arkansas
(9)-(8) is Illinois to Texas
(9)-(6) is Illinois to Arkansas
(9)-(10) is Illinois to Chicago

** 12,000 Btu Illinois coal and 8,000 Btu western coal.

Presently, there is a shortage of hopper cars [4]. Two thousand sixty additional 103.5-ton capacity cars would be needed for the 25 million tons of coal per year unit train system as well as ninety 3,000 hp diesel locomotives (or thirty 10,000 hp gas turbine locomotives). This would require about 75,000 tons of steel. The double track would need about 550,000 tons of steel to last 25 years. The capital required for a unit train system of this size for 30 mph hauling, including only track upgrade, is $116.8 million and, if starting with new ties and rails, is $394.4 million.

## 4. Future of Coal Transport by Rail

An inflation rate of only 7 percent results in a cost doubling every ten years. However, what is important is the relative effect of inflation on competing transport modes. With long overdue improvements, the railroads may be able to compete because of their high energy use efficiency. If diesel fuel becomes scare or too high priced, future locomotives may be powered by gas turbines using methanol for gasification or electricity from coal burning or nuclear power stations.

Because of the heavy loads and fast speeds of a unit train, continuous rails and concrete ties [13] and a continuous concrete slab roadbed [14] may be used to decrease maintenance. Increased traffic calls for improved signaling and switching systems and more overpasses.

The operation of unit trains suffers from the lack of a back haul to the mining area. It is here that the biggest opportunity for cost reduction exists. Even a marginal system, such as sewage for fertilizer and ash from coal for land reclamation, could make the return trip productive.

Rail operation may be further facilitated by the use of pneumatic pipelines. While high pressure, long distance pneumatic systems remain to be developed, short distance pneumatic pipelines of one to 20 miles can be furnished with current technology. These lines, carrying up to 2,400 tons per day of 2 in. by 0 in. coal can be used in place of abandoned rail lines in gathering to, and distributing from, unit train terminals.

Rail transportation's biggest hurdle is its non-competitive rate structure and the progressive deterioration of right-of-way, track and equipment due both to past loss of revenues and the expenditure of revenues on non-transport investments rather than on operation and maintenance. There are profitable railroads. Some badly managed systems would disappear without explicit government subsidy or other forms of federal aid. They have not already done so because they have not been permitted to become bankrupt [15]. Given the level of subsidy and government aid, one solution is for the government to own and maintain alternative unprofitable tracks. Railroads would become similar to highways and rivers. Unprofitable tracks need to be studied to see if their service could be carried out profitably by other modes of transportation, alternative management, bankruptcy and reorganization or outright federal ownership in the national interest. Subsidies or federal ownership of the tracks should be the last resort and should be compared with those for highway, river, and air transport so that intermodal competition can be maintained.

## C. Slurry Pipelines

Two slurry pipelines have been built and tested. The first was the 108-mile, 10-inch pipeline completed in 1957 for shipping coal from the Consolidated Coal Company mine in Cadiz, Ohio, to the East Lake Power Plant of the Cleveland Electric Illuminating Company [16]. Its cost of operation became unfavorable subsequent to the downward adjustment of competing unit train rates. Recently, it has been used for removing garbage from Cleveland. The second pipeline is the 273 mile long, 18-inch pipeline connecting the Black Mesa mines to the Four Corners Power Plant. It was built because of its economy compared to the cost of building 150 miles of new railroad to connect with the Santa Fe railroad at both ends [17]. Much has been learned from its design, operation, and costs. The Black Mesa Pipeline provided a basis for projecting the needs and costs of new routes for coal shipment via slurry pipelines. These pipelines are marked 1-2 and 3-4 on the map shown in Figure 5.

The most undesirable feature of a slurry pipeline is the water requirement. The pipeline needs large quantities of water for product flow. In the western mining area, water is in relatively short supply. At the destination, separation yields a residual "ink" which cannot be dumped into rivers. At the Four Corners Plant, water must be evaporated to prevent pollution. Piping the waste water back to the starting point for reuse in the slurry would require a 40 percent higher owning and operating cost of the shipped coal because the waste water must be pumped upgrade to the mining area.

The second problem is the need to dump the paste-like slurry from all previous sections in the event of a pipeline break or total power failure at a pumping station. This may

amount to as much as a million tons of coal [21]. There is no immediate solution to these two problems. Potential environmental impacts could prevent the utilization of slurry pipelines.

## 1. Proposed Systems Under Construction

Given a possible tripling of coal utilization [18], particular routes may be expected to handle even larger increases. Prominent are those from Gillette, Wyoming, to White Bluff, Arkansas, and from Craig, Colorado, to Houston, Texas [19]. Both are based on low sulfur western coal and utilize gasification at the destinations. Both slurry pipeline and railroads [3] have been considered. The assumption has been that only low sulfur, low Btu coal (less than one percent by weight and about 8,000 Btu/lb) will be used.

An alternate source of coal that will become useful with the anticipated development of methods for using high sulfur coal for gasification is high Btu (12,000 Btu/lb) sulfur (up to 5 percent) Illinois coal. Shipments would include those from southern Illinois to Chicago or to Arkansas and Texas via unit trains or slurry pipeline. High Btu coal gasification at convenient points followed by pipelining to the consumption points is another alternative.

## 2. Costs

Future cost trends and the economic and environmental impact of slurry pipelines can be seen in the recent plan of the Wyoming to Arkansas line [20] as well as from reports on the Black Mesa pipeline [21,22]. Several economic analyses of slurry pipelines have been presented [2,23]. The difference in cost escalation rates of 4 percent for the pipeline and 7 percent for rail [12] are suggested. It should be noted,

however, that a 4 percent inflation rate is far below that predicted for future onshore U.S. oil pipelines. Unless it can be shown that slurry pipelines are intrinsically different, the 4 percent rate can be substantially increased. The high costs of preparation and separation were especially noted by Hughes [24]. Data from these sources were used in the computations leading to Table 5 which summarizes the cost and physical magnitudes of several of the pipelines identified in Figure 5. Physical quantities of particular interest are water requirements (acre-foot/year), total installed horsepower, and coal hold-up. The costs can be compared to unit train costs of operation to the same destination. Slurry pipelines cost one-half as much as a new railroad but are double the cost of the best upgrading of existing railroad. The large coal hold-up in a slurry pipeline (855,000 tons of coal in the proposed Wyoming to Arkansas line) poses an unsolvable problem in case of power outage. It also leads to significant storage problems if the receiving facility is temporarily not operating.

The topology of the Black Mesa pipeline has been presented in several references [21,22]. There is a relatively easy downhill trend for the Wyoming to Arkansas pipeline but the Colorado to Texas line must cover difficult terrain.

Pipeline costs are given in Table 5. Note that variations are around 1¢/ton-mile because of possible state taxes. Also included in Table 5 are the costs of unit train shipments for those routes shown in Figure 5, assuming the use of available railroads. The method of arriving at the rail figures for 30 mph (loaded) to 60 mph (empty) and 50 mph (loaded) to 60 mph (empty) is given in previous studies [25] for various qualitites of railroads including new roadbed and rail, new rails and ties, or track upgrading. This com-

Table 5

Costs of Slurry Pipeline in Comparison to Rail
(Costs in Million Dollars)

| | Ohio (1)-(2) | Black Mesa (3)-(4) | Wyoming - Arkansas (5)-(6) | Colorado - Texas* (7)-(8) | Illinois - Chicago (9)-(10) Illinois - Arkansas (9)-(6) | Illinois - Texas* (9)-(8) |
|---|---|---|---|---|---|---|
| **CAPITAL COSTS:** | | | | | | |
| A. Preparation equipment and wells | | 50 | 90 | | 90 | 90 |
| Tons/year | 1.5x$10^6$ | 5x$10^6$ | 25x$10^6$ | 25x$10^6$ | 25x$10^6$ | 25x$10^6$ |
| B. Piping and installation | 10"D(100mi) | 18"D(273mi) | 38"D(1040mi) | 38"D(1200mi) | 38"D(300mi) | 38"D(700mi) |
| Electrical transmission (1 pumping station/90 miles) | | 60 | 894 | 1,133 | 261 | 609 |
| C. Separation plant and water disposal | | 40 | 50 | ——— | 50 | 50 |
| TOTAL CAPITAL COSTS | | 150 | 1,034 | 1,133 | 401 | 749 |
| **ANNUAL COSTS:** | | | | | | |
| A. Annual fixed charge on debt. Average rate base. | | 75 | 517 | | 300.5 | 374.5 |
| Debt Retirement | | | | | | |
| Rate base (13.4%) | | 10.1 | 69.3 | | 26.9 | 50.2 |
| Federal Tax (28%) | | 2.5 | 16.9 | | 6.6 | 12.3 |
| Depreciation (25 years) | | 6.0 | 41.4 | | 10.0 | 30.0 |
| (State Tax, 2% on Inv.) | | (2.0) | (20.7) | | (8.0) | (15.0) |
| Total Debt Retirement | | 21.6 | 148.3 | | 51.5 | 107.5 |
| B. Operating Labor Direct (no. of men) | | 1.6 (84) | 4.6 (245) | | 2.9 (152) | 3.6 (191) |
| Administrative | | 0.8 | 2.3 | | 1.4 | 1.6 |
| C. Material and maintenance supplies | | 1.0 | 6.0 | | 4.0 | 5.0 |
| Total of B and C | | 3.4 | 12.9 | | 8.3 | 10.4 |
| D. Power (installed horsepower) | | 1 (21,000) | 15.9 (190,000) | (210,000) | 7.4 (55,000) | 12 (128,000) |
| E. Water (acre/foot/year) | | 0.5 (3,000) | 3.5 (15,000) | (15,000) | 3.5 (15,000) | 3.5 (15,000) |
| TOTAL ANNUAL COSTS | | 26.5 | 180.6 | | 70.7 | 133.4 |
| (Total annual costs w/o state tax) | | (24.5) | (159.9) | | (62.7) | (118.4) |
| F. | | | | | | |
| a. $/ton including state tax | | 5.30 | 7.22 | 9.11 | 2.83 | 5.34 |
| b. $/ton excluding state tax | | 4.69 | 8.40 | 8.12 | 2.51 | 4.70 |
| c. $/$10^9$ Btu-mile including state tax | | 1.21 | 0.43 | 8.48 | 0.39 | 0.32 |
| d. $/$10^9$ Btu-mile excluding state tax | | 1.07 | 0.39 | 0.43 | 0.35 | 0.28 |
| e. ¢/ton-mile including state tax | | 1.94 | 0.69 | 0.76 | 0.95 | 0.76 |
| f. ¢/ton-mile excluding state tax | | 1.72 | 0.62 | 0.68 | 0.84 | 0.68 |
| Hold-up in Pipe in tons at 3.5 mph | | 46,000 | 855,000 | 1,000,900 | 250,000 | 580,000 |
| Comparison to Rail in cents/ton-mile | | | | | | |
| New road, 50-60/30-60 mph | | | 1.15/1.13 | 1.14/1.13 | 1.78/1.76 | 1.19/1.17 |
| New rail, 50-60/30-60 mph | | | 0.33/0.31 | 0.33/0.32 | 0.50/0.49 | 0.34/0.32 |
| Track upgrading, 30-60 mph | | | 0.19 | 0.20 | 0.30 | 0.20 |
| Trains on the road, 50-60/30-60 mph | | | 13/16 | 13/16 | 3/5 | 10/14 |
| Total locomotive horsepower: 50-60 mph | | | 450,000 | 530,000 | 175,000 | 420,000 |
| 30-60 mph | | | 250,000 | 300,000 | 90,000 | 240,000 |
| Cost $/$10^9$ Btu-mile, new rail 50-60 mph | | | 0.206 | 0.206 | 0.162 | 0.142 |

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* Difficult Terrain

parison shows that, except for building an entirely new railroad, slurry pipelines cannot compete in cost of shipment even with the most complete upgrading of the railroad. The rail advantage is even greater if one considers that the railroad may carry other, non-coal shipments while the slurry pipeline is a one-material shipper. The use of complementary pneumatic pipelines in conjunction with rail would further improve the economics of the railroad.

### 3. Environmental Impact

The design of the Black Mesa pipeline specifies dumping the coal slurry in case of power failure. The problem for a 273-mile line with three pumping stations and a 46,000-ton coal hold-up is minor compared to a 1,040-mile line with 10-12 pumping stations and a hold-up of 855,000 tons.

In case of power failure or pumping outage at a station, the slurry cannot be stopped lest deposition and plugging occur. The procedure entails introducing water into the pumps at the upstream station and dumping the slurry ahead of the non-operating station. The latter might require an auxiliary water pump and water supply at the next operating station as suction alone might not be sufficient to pull the slurry through. The case of a line break can be similarly handled at upstream points; however, there is no provision made such that the downstream pump can pull the slurry through the downstream section of the break. Hence, the design excludes line breakage. Bacchetti [27] has indicated that no outages have occurred in the Black Mesa pipeline. A controlled shut-down is no problem: stopping the coal supply at the starting point and introducing water instead will clear the line in 78 hours by replacing slurry with water.

In a 1,040-mile pipeline, it will take 12 days, 9 hours to clear the line in a controlled shutdown. While line breakage might be excluded by extra-heavy piping, there is no guarantee that a power outage will not occur at one of the 10 to 12 pumping stations. Provision for dumping at a station calls for a large water supply and auxiliary water pumping capacity at that station.

### 4. Economic Impact

The locomotive horsepower required for a unit train shipment is of the same order of magnitude as the installed horsepower for a slurry pipeline of similar length. The manufacture of locomotives and cars for a 16-train unit train operation includes 64,000 tons of steel. This may be compared to a slurry pipeline (Wyoming to Arkansas) using 1.1 million tons (1.0 million metric tons) of steel for the pipeline alone, or almost twice as much as that required for the rails of the 1,100 miles of double track railroad. Therefore, the material requirements for upgrading the railroad are less than for a new pipeline; the rolling stock is actually a small factor in the material investment.

### 5. Comparison to Rails

A 7 percent annual escalation of costs for railroads and a 4 percent annual escalation for slurry pipelines has been predicted [23]. However, for the present comparison of 1975 installation costs, a uniform 7 percent annual escalation of costs is assumed.

In terms of engineering and operation, a slurry pipeline must be designed for an optimum throughput and must be kept filled. The flow rate must be kept near the optimum for

economic operation. In order to double the capacity of a given slurry line, four times the pumping power and fuel is needed. That is why slurry lines are designed for an optimum throughput with a resultant lack of operating flexibility.

The cost of multiple pipelines to improve reliability of operation is exhorbitant. The capacity of two 27-inch pipelines, equaling that of the 38-inch pipeline for 25 million tons per year of coal, would cost 1.6 times as much to build. (According to the U.S. Army Corp of Engineers cost predictions: 27-inch = 38-inch$[(27/38)^{0.65}]$.) because of higher friction in smaller pipes, they would require 1.45 times the pumping power and fuel needed for the larger diameter lines [30].

Rails are far more flexible during upgrading and development and growth can be programmed. If there is an accident, there is relatively little damage. Also, with double track, because of switching systems, parts of one track can be closed for upgrading or repair without impeding traffic.

## D. Pneumatic Pipeline

Based on current practice, a pneumatic pipeline appears most competitive with trucks and belt conveyors for gathering to, and distributing from, a rail terminal. Given the trend towards the abandonment of branch lines, this is desirable. Details are summarized in Table 6, showing the design variables. Pressure feed is limited to 20 psig such that high pressure feed bins and switching are not needed while the vacuum suction is limited to -10 psi vacuum as an economic limit. Table 6 shows various push-pull options. Table 6 shows distances of up to 4.5 miles; however, a longer distance line can be designed. For instance, one way to cover a dis-

**Table 6** Design Parameters--Current Pneumatic Pipelines for Short Distances, 2 in. x 0 in. (5.08 cm by 0 cm) Coal, Unpressurized Coal Feed

| | | |
|---|---|---|
| Capacity | | |
| Tons/yr; | 100,00 | 500,000 |
| Tons/hr | 20 | 100 |
| Pipe Diameter, in. (cm) | 10 (25.4) | 18 |
| Air Flow, scfm | 2,500 | 12,000 |
| 1,000 ft (304.8 m) Transfer | | |
| Pressure Drop, psi | 2.8 | 1.4 |
| Inlet Pressure | Atmospheric | Atmospheric |
| Discharge Suction, psi vac | -2.8 | -1.4 |
| Blower hp at Discharge | 50 | 125 |
| Installed Cost | $200,000 | $600,000 |
| 1 mile (1.6 km) Transfer | | |
| Pressure Drop, psi | 14.7 | 7.3 |
| Inlet Pressure, psig | 15* | Atmospheric |
| Blower hp at Inlet | 250 | --- |
| Discharge Suction, psi vac | Atmospheric | -7.3 |
| Blower hp at Discharge | 0 | 650 |
| hp/(ton/hr) | 12.5 | 6.5 |
| Installed Cost | $216,000 | $648,000 |
| 1.5 Mile (2.4 km) Transfer | | |
| Pressure Drop, psi | 22 | |
| Inlet Pressure, psig | 15* | |
| Blower hp at Inlet | 250 | |
| Discharge Suction, psi vac | -7 | |
| Blower hp at Discharge | 125 | |
| Installed Cost | $226,000 | |
| 2 Mile (3.2 km) Transfer | | |
| Pressure Drop, psi | | 14.7 |
| Inlet Pressure, psig | | 15* |
| Blower hp at Inlet | | 1,250 |
| Discharge Suction, psi vac | | Atmospheric |
| Installed Cost | | $696,000 |
| 3 Mile (4.8 km) Transfer | | |
| Pressure Drop, psi | | 22 |
| Inlet Pressure, psig | | 15* |
| Blower hp at Inlet | | 1,250 |
| Discharge Suction, psi vac | | -7 |
| Blower hp at Discharge | | 600 |
| Installed Cost | | $744,000 |
| 4.5 Mile (7.2 km) Transfer | | |
| Pressure drop, psi | | 30 |
| Inlet Pressure, psig | | 20** |
| Blower hp at Inlet | | 1,650 |
| Discharge Suction, psi vac | | -10*** |
| Blower hp at Discharge | | 800 |
| Installed Cost | | $872,000 |

*With rotary feeder (A. S. H. Fluid Transport Division, Envirotech Corporation King of Prussia, PA 19406).

**Limit of rotary-valve feeder.

***Limit of Roots blower.

tance of 18 miles is to repeat by using four modules of 4.5 miles each. Since the gravity effect is not a big factor in the pressure drop in a pneumatic system, the latter can cover the steepest terrain using the most direct route. Since very little ground preparation is needed for installing a pneumatic system, it is almost portable if relocation is needed.

The cost of shipment via these pneumatic pipelines of low capacity ranges from 3¢/ton-mile at between 400 tons per day and 2,000 tons per day to from 1 to 2¢/ton-mile for shipment above 2,000 tons per day. Because this system is more recent than the others, its details are delineated below.

## 1. Pneumatic Coal Transport System [1,28]

A technical and economic evaluation of pneumatic coal pipelining has been made in an experimental installation as shown in Figure 6. Test parameters include the coal rates and sizes that can be efficiently conveyed pneumatically, pipe sizes, air volume and compression power requirements, and pipe erosion. Technical feasibility depends mostly on whether a pneumatic system can be successfully operated and whether it can meet or exceed the haulage capabilities of existing systems. Economic feasibility depends largely on the capital and operating costs of air compression equipment. Haulage capabilities and air requirements thus appear to be the major factors needing study. These, in turn, vary in accordance with characteristics of the pneumatic system (horizontal or vertical, vacuum or pressure); the diameter, length, and configuration of the pipe; and the size, size distribution, moisture content, and ash (slate and shale) content of the coal.

Figure 6 is a sketch of the experimental pneumatic coal transport pilot plant which incorporates components which

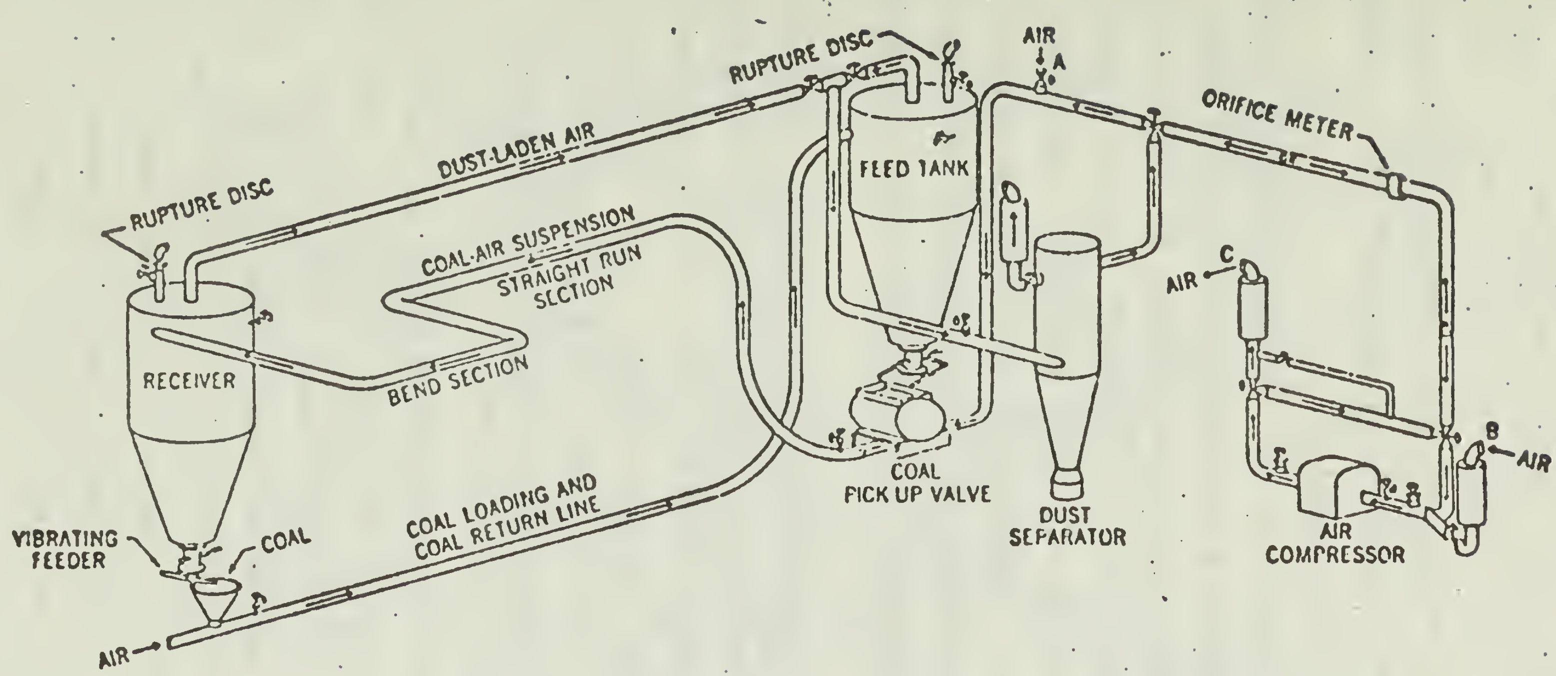


Figure 6. Sketch of Experimental Pneumatic Coal Transport Plant showing Typical Components

might be used in actual installations, although not simultaneously. Four pipelines of different diameters consisting of straight horizontal runs and bends lead from a 7-ton feed tank to a receiver. The four pipelines are 2, 4, 6 and 8 inches in diameter and are made of mild steel. Straight runs of 200 feet in length are followed by shorter runs containing 8, 6, and 4 foot bends in succession.

The 2,500 cfm compressor in the system permits operation at vacuum to 20 inches mercury and pressures to 20 psig. During vacuum operation, air enters the system at point A, picks up the coal at the rotary valve (Figure 7), and the coal-air suspension is pulled through the test piping. The coal is deposited in the receiver. Dusty air from the receiver is pulled into the dust-separator for cleanup, and the clean air proceeds through the compressor and is discharged into the atmosphere.

When the system is operated under pressure, air enters at point B, is pulled through the compressor, pressurized, and piped to the coal pick-up valve. The coal-air suspension is pushed through the test piping and the coal is deposited in the receiver. Again, dust-laden air from the receiver is forced into the dust separator for cleanup followed by exhaust to the atmosphere.

Mine run coals of varying moisture and ash content and crushed to various sizes up to 2 inches are to be fed from the feed vessel into the 100 tph rotary valve feeder. Feed rate is controlled by a variable speed vibratory pan feeder that drops the coal by free-fall into the rotary valve feeder. With this method of feeding, the rotary valve feeder (Figure 7), which will handle only small particles under normal choke-feeding conditions, can satisfactorily feed the larger 2-inch coal sizes.

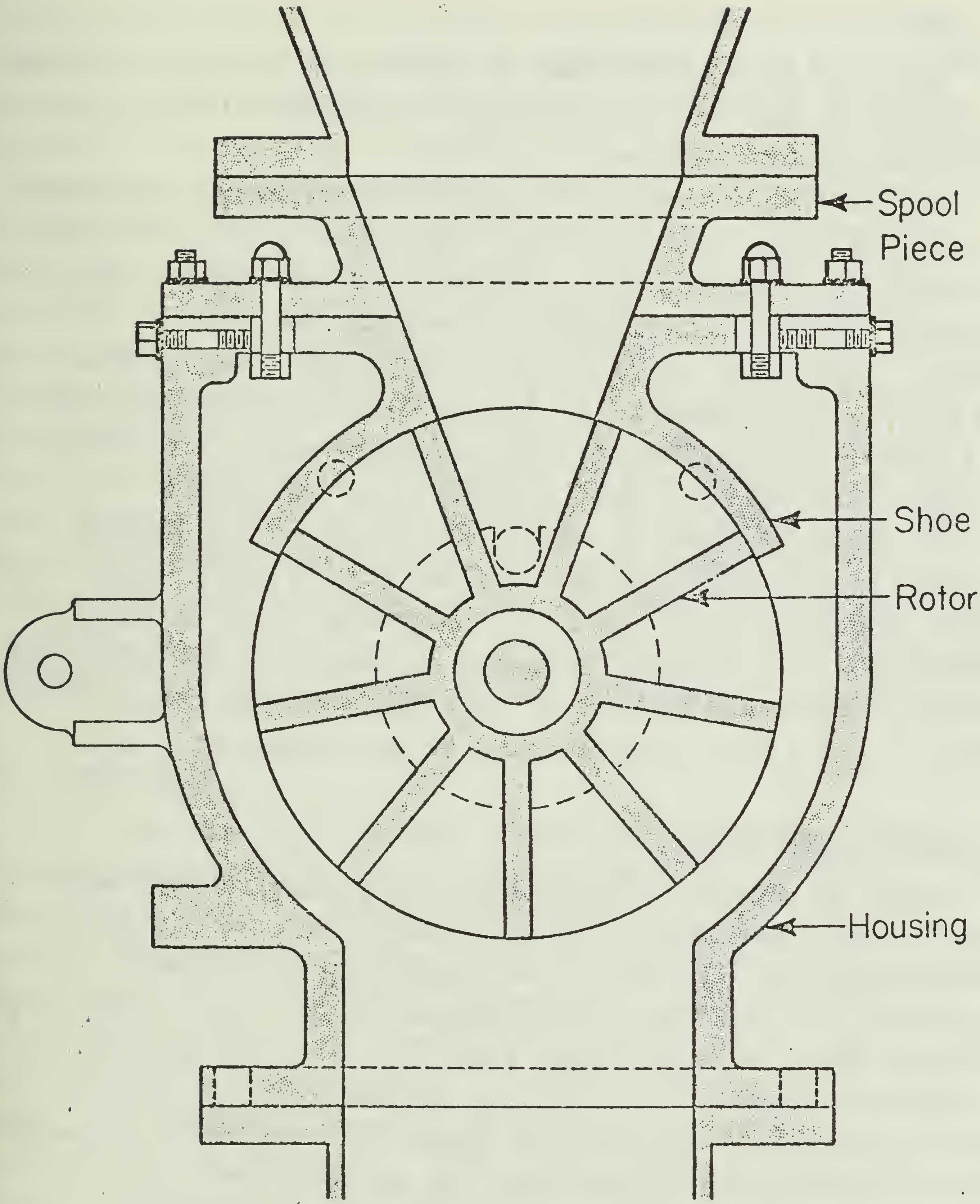


Figure 7. Rotary-Valve Feeder

## 2. Feed

The practices established in the design and operation of the pneumatic mine hoist [29] might be applied directly to the transportation system.

At the mine, material is transferred from the concentrator pile by means of a front-end loader and inlet to an RTL 200 Feeder is controlled by a Syntron vibrator unit. The complete system is operated by one man on the control console. An output up to 40 tph is achieved. Two hundred tph systems are commonplace. Materials with pieces as large as 3 inches can be handled. An alternate means is to have the mine cars unloaded onto a conveyor to the feeder.

For handling coal as mined, the vibrator feed, which includes large lumps, can be diverted from a grate which allows passage of 2 in. by 0 in. coal to a 10 by 15 jaw crusher set at 2 inches. A manual deflector at the discharge of the crusher into the inlet joins the coal from the vibrator grate with that diverted to the preparation unit.

## 3. Safety Features

When the system is operating, the possibility of explosion in the pipelines is remote because the high transport velocities make it difficult or impossible for flames to propagate. In the vessels and separator, and during start-up and shut-down, velocities are lower and a remote possibility of explosion exists. As a safety precaution, inert gas is piped to various points of the system for purging to prevent fire and explosions during start-up and shut-down with sufficient inert gas being introduced to keep the $O_2$ concentration below 15 volume-percent.

The system can be designed to contain an explosion, according to approved practices in the installation and opera-

tion of pulverized fuel systems. Such practices require equipment to withstand explosion pressures up to 50 psig when pneumatically conveying powdered coal at absolute pressures up to one atmosphere. Equipment rated proportionately higher is needed for higher operating pressures. Vacuum operations require that all the main vessels be capable of containing explosive pressures up to 50 psig. The separator and the receiver are operated under low pressure, not exceeding 3 psig, which requires that they be designed to contain an explosive pressure of 60 psig. A 3 psig rupture disc limits the pressure in the receiver. This limited operating pressure can be maintained even with a 20 psig pressure at the coal pick-up point, since nearly all of this 20 lbs is used to transport the coal through the experimental pipeline. Both vessels are designed for 150 psig working pressures and have been previously operated at pressures up to 60 psig; the separator has been pressure tested satisfactorily to 60 psig.

4. Application

It appears that the most immediate applications of the pneumatic pipeline is that of a transport system for coal in conjunction with the use of the right-of-way of a railroad system. Supplying a large gasification facility from a railroad terminal by a pneumatic pipeline is desirable because the 0.25 in. by 0 in. (6 mm by 0 mm) coal size is correct for most gasification processes. Because of the speed of shipment in a pneumatic system, storage will be needed only at one end of the pipeline. This is significant considering the volume required for 60-day storage for a plant using 25,000 tons (23,000 metric tons) of coal per day. A slurry pipeline can also be supplied from a railroad; however, the requirement of a 14 by 325 mesh coal size for the slurry

makes the dried coal unsuitable for feeding a gasification system.

## 5. Long Distance Pneumatic Pipelines

Several recent findings point to the adequacy and versatility of pneumatic pipelines: (1) The pipe flow friction factors on which the 1962 Bureau of Mines estimates [16] were based were 10 to 50 times higher than those determined from recent experimental data [31] and experiments in England [32]. (2) The present study shows that a long distance pneumatic pipeline should be neither a vacuum suction system nor a 100-atm system. Only these two systems were considered in the 1962 report [16]. The optimum appears to be about 10 atm at a mass flow ratio of coal-to-air of nearly 10. With this condition, coal occupies only 10 to 15 percent of the volume. Power failure, if it occurs, will temporarily close down the line but will not cause plugging of the pipes. (3) Pumping power requirements and pipeline costs are near those of a slurry pipeline. However, preparation costs amount to only the first-stage crushing in a slurry facility, and the cost of separation is nil. (4) The pneumatic pipeline can be designed for short or long distance transport. It is compatible with rail either for delivering to loading facilities or for distributing from terminal points.

The present study shows that the pipeline pressure should be nearly 10 atm rather than a low of about 1 atm or a high of 100 atm. The selection of the pipeline pressure with respect to the states of a suspension has already been solved.

It has been shown by outlining the design procedures for a pneumatic pipeline that, for transmission over distances of hundreds of miles, there is a choice between a small pressure ratio of pumping of, say 1.6:1 of inlet-to-outlet with short

station spacing of less than 20 miles, and long station spacing of about 100 miles with proper suspension velocity over the whole length following the design of Topper, et al [33]. Because of the decrease in density (or increase in volume) of a gas as the pressure decreases along the pipeline, it is readily shown that long station spacing must be accomplished by increasing the pipe diameter via telescoping as the flow proceeds. In this way, the flow velocity is kept just high enough for the suspension but minimizes the friction loss. Therefore, an optimum selection of various lengths of standard pipe of various diameters must be made.

In the pneumatic transmission of coal, it has been shown that, because of wear and safety, a large mass ratio of coal-to-air is desirable together with a high air density and an intermediate size of the coal particles; below 0.25 in. by 0 in. size for short distances of 3 to 5 miles. Current practical experience can be found in pneumatic hoisting from mines [31,29].

Table 7 illustrates pertinent engineering parameters for the comparisons. For a station spacing of 20 miles at a 1.6:1 pressure ratio, the unit cost amounts to 0.4¢/ton-mile for an unburied pipe and 0.7¢/ton-mile for buried pipe. Table 8 also shows a comparison of typical pipeline systems for natural gas and oil showing the availability of options for shipping coal to gasification plants for local use or to gasify coal to be pumped into gas pipelines.

Flexibility of a pneumatic pipeline is seen over short distances. The planned 3.5-mile pipeline for the Baldwin Power Plant of the Illinois Power Company is a case in point. The short distance permits a rather simple design with a compromise in power consumption and coal size. It appears feasible to transfer 18,000 tons/day of coal (below 1 in.

Table 7

Comparison of High Pressure Transmission
of Coal in Air Suspension with Other Systems

| Form | Gas | Oil | Coal (Air Suspension) | Coal (Water Slurry) |
|---|---|---|---|---|
| Heating Value | 1,000 $Btu/ft^3$ | 18,500 Btu/lb | 12,000 Btu/lb | 12,000 Btu/lb |
| Flow | 240 mmscfd | 37,000 bbl/day | 10,000 tons/day | 10,000 tons/day |
| Energy Density, Btu/ft | $6.8 \times 10^4$ | $9.68 \times 10^5$ | $7 \times 10^4$ | $5 \times 10^5$ |
| Practical Flow Velocity, fps | 30 to 60 | 5 to 10 | 20 | 5 |
| Pipe Diameter, in. | 16 to 12 | 10 to 7 | 14 in. | 14 in. |
| Power Requirement, hp | 25,300 | 26,850 | 24,450 | 20,240 |
| Volume Fraction Solid | | | 4.5% (to 9.1%) | 32.4% |
| Cost | | | 0.4 to 0.7¢/ton-mile | 0.7 to 1.1¢/ton-mile |

size instead of an upper limit of 0.25 in.) with a compressor of 2,500 hp and 17,000 scfm at a maximum pressure of 4 atm. This allows for a gradient of 1.5 percent to a 300 foot higher elevation at the delivery point from the starting point. The pipes will be unburied, 14 inches in diameter for the first 1.5 miles, 16 inches in diameter for the next mile, and 18 inches in diameter for the last mile ("telescoping"). Coal feeding is accomplished by alternately charging and discharging two bins with coal locks and valving. Unless otherwise cooled, the compressed air is initially at 350°F; hence, some wetness in the coal is readily accommodated. The pressure is nearly atmospheric at the delivery point.

A comparison has been made with a conveyor belt. The costs are high because of the short distance, i.e., 1.14¢/ton-mile for the pneumatic pipeline and 3.83¢/ton-mile for the conveyor belt, both unburied. However, the pipeline is still more economical than other means of transportation even over such a short distance. If the pipeline were buried, the cost would be 1.55¢/ton-mile.

It takes less than four minutes for a batch of coal to clear the pipeline with a hold-up of 50 tons of coal in the pipe. Coal storage needs can be simplified because of this short response time.

The desirability of substituting a pneumatic pipeline where new rail is to be built is readily seen in the case of coal shipments from the Black Mesa Mine to the Four Corners Power Plant [17]. The 273-mile slurry pipeline was built as an alternative to adding 150 miles of new rails to the 250 miles of existing Santa Fe tracks. The decision is easily understood based on the following data:

Slurry Pipeline - 273 miles at 1¢/ton-mile or $2.73/ton.

Rail - 250 miles at 0.6¢/ton-mile; 150 miles at 1.0¢/ton-mile, $3.00/ton. However, if a pneumatic pipeline were built to connect with the existing rail:

Rail - 250 miles at 0.6¢/ton-mile, 150 miles pneumatic at 0.5¢/ton-mile, $2.25/ton.

Pneumatic Pipeline - 273 miles at 0.5¢/ton-mile, $1.17/ton.

## E. Publication and Utilization

In addition to the documents presented in Appendix F, at least one utility is interested in the pneumatic pipeline. Discussion with Peabody Coal Company and Illinois Power Company personnel have indicated to us that the present 3.5-mile (5.6 km) unit train supplying coal from the mine to the Baldwin Power Plant will be discontinued if other suitable means of transporting coal can be found. Our analysis indicates that by using a telescoped pneumatic pipeline, the shipping cost over this short distance will be 1.14¢/ton-mile (0.79¢/mt-km) compared to 3.73¢/ton-mile (2.57¢/mt-km) by conveyor belt system. There is a definite interest in using the pipeline system once the finished design is available.

Based on the transportation data, a short project was completed at the request of the Federal Energy Agency (Office of Coal). M. Rieber and S. L. Soo, <u>The Feasibility of Coal Mine Cooperatives: A Preliminary Report and Analysis</u>, CAC Document No. 157P, April 1975, pp. 118. Copies are available from the FEA.

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# SECTION V: COMPARISON BETWEEN FLUE GAS DESULFURIZATION SYSTEMS AND LOW BTU GASIFICATION CONFIGURATIONS

## Introduction

Since the passing of the 1970 Clean Air Act, there has been a continuing debate regarding the use of high sulfur fuels. The most abundant high sulfur fuel available in the continental United States is coal. In the intervening five years a great deal has been written and said concerning ways to utilize high sulfur coal. During these five years the utilization of stack gas scrubbers for removing $SO_2$, the primary pollutant evolved when high sulfur content coal is burned, has been considered the primary option open to potential users of high sulfur coal. Recently, low and medium BTU gasification systems have been proposed as another option for utilization of high sulfur fuels.

In an attempt to deal with the mideast oil embargo of 1974, a plan of action was proposed to make the U.S. self-sufficient in energy production by 1985. The implications of such a proposal on coal utilization are enormous. Even assuming that conservation measures will reduce the U.S. energy demand by as much as 10-15 percent, the production of coal would have to be doubled in the next ten years.[1] This requires the equivalent of opening one new strip and one new deep mine every month for the next ten years. This is an almost impossible task. To further complicate an already difficult situation, the majority of the coal available for immediate mining has a sulfur content which will not be able to be legally burned without adequate sulfur removal capabilities after May 30, 1975. This, then, defines the energy-environmental dilemma.

To gain some perspective regarding the number of power plants involved in such a dilemma consider the following facts. The report of the Hearing Panel on power plant $SO_2$ compliance[2] indicated, that in 1972, there were 970 fossil fuel-steam power plants generating 302,000 mw of electricity. Of these 55 percent (166,000 mw) were coal fired, 17 percent (51,000 mw) were oil fired and 28 percent (85,000 mw) were gas fired. The report estimated that there would be 209,000 mw being generated in 1975 by coal fired plants. Of these plants, 123,000 mw are not expected to need additional emission controls to meet primary air quality standards, 23,000 mw will require washing of high sulfur coal or blending with low sulfur coal and 63,000 mw will need elaborate sulfur control. After 1975, EPA estimates that 24,000 mw will be added each year, with 14,500 mw of these units being coal fired. Further, many units currently fired with oil or gas may be forced to switch to coal because of oil and gas shortages due to supply or to economics. One of the most obvious short term options for dealing with the sulfur problem is to switch all the units to coals having low sulfur contents. The SOCTAP[3] report states that a possible deficit on low sulfur coal in 1975 of as much as 250,000 tons may exist. Expressed as steam electric capacity, this is equivalent to 100,000 mw of capacity.

In the discussion which follows, two additional options for dealing with the utilization of high sulfur coal will be considered: stack gas scrubbers and low BTU gasification.

Stack gas scrubber strategies for controlling sulfur oxide emissions were put forth by United States Environ-

mental Protection Agency. The reaction of the industrial community was that the systems were not reliable, were costly, and offered no hope of contributing to the overall economic strength of the industry. Low BTU gasification strategies were basically the brain child of industry. In contrast to the flue gas desulfurization systems (FDS), industry viewed low BTU gasification as a costly alternative but one which has the potential to contribute to the economic growth of the industry over the long term. For this reason, it is felt that low BTU gasification systems offer the best alternative to utilize high sulfur coals while at the same time improve our overall energy supply picture.

In a study which is assessing the future supply curve for coal under a variety of scenarios, however, one must consider both these strategies for dealing with high sulfur coal in an environmentally acceptable manner.

## Stack Gas Scrubbing Systems

Sulfur dioxide removal processes are often described in terms of how the waste products are handled. One group of processes deals with the waste disposal problems by discharging absorbents to a sewer, by impounding or by removing the suspended solids from the slurry and discarding. These systems are called "throw-away" processes. The "throw-away" processes are inherently potential sources of water pollution and solid waste disposal problems. Another group of processes deals with the disposal problem by regenerating the spent solvent so as to recover the $SO_2$ absorber material for reuse in the scrubber and at the same time produce a useful by-product. These systems are called

regenerative processes.

When evaluating $SO_2$ removal efficiencies, it should be noted that removal efficiencies of the order of 75 percent are needed to meet the New Source Performance Standards with 3 percent sulfur bituminous coal. In general, efficiencies of 85 percent are sufficient to meet most state sulfur dioxide emission regulations.

According to a recent SOCTAP report,[3] the most successful operating $SO_2$ stack gas clean up processes are the Chemico calcium hydroxide scrubber which has been operating on a coal fired boiler at the Mitsui Aluminum Plant in Japan since March 29, 1972; a Babcock and Wilcox limestone scrubbing unit operating on Commonwealth Edison's Will County Plant near Chicago; the Wellman-Lord regenerable sodium sulfite scrubbing process which has been operating at the Japan Synthetic Rubber Chiba Plant since 1971; and the Chemico magnesium oxide system at Boston's Edison Mystic Station which started up in 1972.

The report went on to say that the Chemico scrubbing plant at the Mitsui Aluminum Plant has exhibited a removal efficiency between 80 and 90 percent, the Wellman-Lord unit at the Japan Synthetic Rubber Plant has operated with a removal efficiency of 90 percent over 9000 hours of operation, the combustion engineering limestone injection/wet scrubbing system has exhibited removal rates in the range of 60-80 percent, and a short term test on the Babcock and Wilcox limestone scrubber at Commonwealth Edison's Will County plant has exhibited efficiencies between 75 and 80 percent. Finally, the Chemico wet magnesium oxide

scrubber at Boston's Edison Mystic Station has demonstrated 90 percent $SO_2$ removal capabilities.

A recent PEDCO[4] report describing the present status of industrial commitments to stack gas scrubbers, as of October 1974, revealed that 99 utility size boilers are committed to some form of FDS. The degree of commitment varies from ordering operational units all the way to only considering FDS units at present. The major conclusion that can be drawn from this report is the almost total commitment of utilities to lime, limestone or lime/limestone FDS processes. The study showed that 81.4 percent or 29,439 mw of generating capacity were to be controlled using lime or limestone processes for controlling sulfur dioxide. Of this total, 12,945 mw or 35.7 percent were more or less irreversibly committed to some form of stack gas cleaning scheme. The remainder still had options open to them.

It is also interesting to note that the number of retrofits are about equal to the number of new boilers. The average size of a retrofitted boiler is 243 mw whereas a new boiler averages 504 mw.

The processes which are currently at the demonstration stage are (1) wet /lime/ limestone, (2) sodium hydroxide, (3) sodium carbonate, (4) magnesium oxide, and (5) catalytic oxidation. The status of a number of additional flue gas desulfurization systems are given in Table 1.

It cannot be emphasized too strongly that although there are four prime flue gas desulfurization systems currently at the demonstration stage, only the wet (lime)

limestone processes are being considered for installation on utility boilers in any great numbers. Since this process is a throw-away process, it presents certain waste disposal problems.

Waste Disposal

One of the major environmental problems facing the throw-away stack gas cleaning processes is the ultimate disposal of the sludge. Both lime and limestone processes generate a large quantity of waste products. By way of example, the National Electric Reliability Council's Report[5] estimates that a single 825 megawatt generating unit will produce 3.63 tons of sludge per day for every megawatt of power which is produced. For this particular installation this would amount to more than 3000 tons of sludge each day which must be placed in a suitable repository. The most common disposal method currently being considered requires gravity settling in lined ponds followed by ultimate disposal in a landfill. Because the sludges are often thixotropic and may absorb water after a rainfall, any soluble salts or toxic elements in the sludge could be leached out and drained away from the disposal site. This, of course, could lead to serious environmental consequences. Based on the land requirements reported for fly ash disposal in the recent SOCTAP,[3] the land requirements for sludge disposal is almost nine times that required for fly ash disposal. Given that 80 out of the 92 planned scrubber installations reported in the PEDCO[4] study are lime or limestone based installations, this sludge disposal problem could be enormous.

Perhaps the most effective way to alleviate this sludge disposal problem is to promote the development of regenerative processes and discourage the further sale of throw-away processes. The rationale behind such a strategy lies in the fact that elemental sulfur is the most desirable product for flue gas desulfurization systems. Elemental sulfur is the preferred waste product because it can be economically stored for subsequent use at some future date, and it is a relatively insoluble and inert material with no apparent major water pollution potential. The difficulty with this strategy is that of unfavorable economics.

## Space Requirements

While it is true that the ground space requirements for certain flue gas cleaning processes vary, the major flue gas scrubbing processes all require essentially the same equipment in the area immediately adjacent to the boiler stack. Since all of the components of the system used need not be located in this area, the overall space required for the installation is not terribly significant for a retrofit installation.

A recent study by the Radian Corporation[6] examined the space requirements for lime/limestone, MgO and sodium based scrubbing processes. All of these processes are expected to have essentially the same space requirements in the area immediately adjacent to the boiler and stack.

The basic process equipment required for lime/limestone processes includes the scrubber, mist eliminator, hold or delay tanks, solid separation devices, a reheat system,

storage bins for the alkaline additive, slurry tanks and pumps and a solid disposal system. The main components of the waste disposal system include a clarifier or thickener, vacuum filter and a method of sludge fixation.

In order to size the area required to house the scrubber it was assumed that the gas velocity in the scrubber was 9.5 ft/sec, and that each scrubber handles 450,000 ACFM. These conditions define the scrubber area required which is 800 $ft^2$. If a 4 sec gas residence time is assumed for the scrubber, the scrubber dimensions would be of the order of 20 ft in diameter and 40 ft high. If a plant burning coal with a 3.5 percent sulfur content was limited to a sulfur emission rate of one lb $SO_2$ per million BTU input, a 450,000 ACFM scrubber module would require a holding tank 50 ft in diameter and 55 ft high. In addition, a mist eliminator having a height twice that of the scrubber would be required on top of the scrubber module.

Following the example used in the Radian report,[6] consider a 550 mw unit burning coal with a 3.5 percent sulfur content. If the holding tanks are placed below the scrubbers, there is a 15 ft space between the holding tanks, the pump houses are 7.5 ft from the holding tanks and the pump houses have dimensions of 30 ft by 60 ft, the total area required for the scrubber installation is approximately 25,000$ft^2$ or 45 $ft^2$/mw. If the scrubber size and pump house dimensions remain unchanged, and it is assumed that there is 15 ft between the scrubbers and 10 ft between the scrubbers and the pump houses, then the total area required is only 13,000 $ft^2$ providing the holding tanks are removed to some remote area or their size

is reduced to fit beneath the scrubber units. This amounts to a space requirement of approximately 24 $ft^2$/mw.

It should be noted that although the above space requirements were based on a 550 mw plant, the result is independent of plant size. The basis for this generalization lies in the fact that the scrubber area is proportional to flue gas flow rate. Since the flue gas flow rate and the size of the plant are also proportional, the ground space required for a scrubber is directly proportional to the size of the unit in mw. The space requirements would change, of course, if the coal sulfur content and heating value were changed.

The Radian Corporation[6] study assumed that the very minimum amount of space required adjacent to the plant was 20 $ft^2$/mw. The impact of this type of load restriction for boilers in the State of Ohio was that about 74 percent of the total capacity surveyed in the State of Ohio had space equal to or greater than the 20 $ft^2$/mw minimum. Although this study was limited to the State of Ohio, there is no reason to believe it is not representative of the entire country.

In a similar study undertaken by the M. W. Kellogg Company,[7] a survey was conducted to determine the applicability of nine different $SO_2$ control processes to existing power plants based on space considerations. The study was limited to large (200 mw or greater) coal or oil-fired power plants. The nine processes included were limestone scrubbing (TVA), limestone injection (TVA), catalytic oxidation (Monsanto), molten carbonate scrubbing (Atomic

International), sodium or potassium sulfite scrubbing (Wellman-Lord), magnesium oxide scrubbing (Chemico), formate scrubbing (Consolidation Coal), and ammonia scrubbing (TVA). The results indicated that, based on space requirements alone, none of the candidate processes could be installed in over 50 percent of the units studied. Further, the maximum theoretical space applicability ranged from approximately 60-70 percent for "throw-away" processes, down to 30-40 percent for the regenerable type processes which produce saleable by-products. The report noted that newer and larger plants could accommodate the processes better than older and smaller ones.

Time Requirements for Installation

Another important parameter in making economic predictions is the time requirement for installation of flue gas desulfurization. The recent hearing panel on sulfur dioxide controls[2] concluded that a reasonable time scale from the decision to control to compliance is broken down as follows: signed contracts in 6-9 months, construction begun 8-11 months, start up in 21-30 months, and compliance in 27 to 36 months. Industry representatives placed the overall period to be from 36 to 48 months.[2]

Tie in Requirements

The normal load cycle for electric power generation peaks in summer and winter due to the extreme temperatures encountered. The high winter peak lead is due to space heating while the summer load peaks are due to space cooling. A typical generating plant is scheduled for

routine maintenance is of the order of one to three weeks. This time space would not be long enough to allow the installation of even the pre-assembled sulfur oxide removal processes. Once every four to five years a generating plant is down for a period of five to eight weeks for maintenance. This time span is considered sufficient[5,6] for the installation of most $SO_2$ scrubbing processes. Based on these figures, a recent report by SOCTAP[3] concluded that on the average a maximum 20 percent of the electrical generating capacity could be retrofitted in any one year. A report by Radian Corporation[6] seriously questioned whether this conversion percentage was realistic. The report stated that the percentage was too high because of the certainty of slippage in many retrofit installations. This is particularly true in the Midwest and East where brownouts have occurred during the past couple of years.

Institutional Barriers

Institutional barriers can combine to delay the ordering, fabricating, assembling, and placing into operation an $SO_2$ scrubbing system. A list of the most important barriers are listed by SOCTAP:[3] 1) The adequacy of the market demand to encourage development of a supply industry; 2) The necessity to maintain adequate electrical reserve generation margin; 3) Lack of process chemical expertise in the electric utility industry; 4) Fuel switching alternatives for higher costs of low sulfur fuels may be passed through to consumers by means of fuel adjustment clauses.

The things that are currently restricting the use of $SO_2$ systems include 1) Lack of confidence in the ability of the

vendors to perform as promised, 2) Anticipation that regulations may be altered in the near future, 3) Potential difficulties in raising capital and obtaining rate increases in covering expenses for pollution abatement, 4) The lack of suitably trained personnel in the industry to evaluate and operate these systems.

Power Requirements for Scrubbers

Recent reports[2,3,4,5] have estimated that between 2 to 7 percent of the power output from boilers outfitted with $SO_2$ scrubbing systems are required to run the FDS. Energy requirements of 4 to 7 percent were reported in the recent EPA hearings on $SO_2$ scrubber technology held in Washington, D. C. in January of 1974[2]. In the SOCTAP[3] report assessing flue gas desulfurization systems, it was reported that the energy requirements to run TVA's Willow Creek No. 8 plant, rated at 550 megawatts, was 24.5 mw. This amounts to roughly 4.5 percent of the total energy output of the plant. Gifford[8] in reporting on the Will County Unit No. 1 of Commonwealth Edison estimated that the power requirements to run the limestone scrubber was 5.1 percent of the unit gross capacity. He noted that this is nearly equivalent to the auxiliary power consumed by the rest of the unit. If a national average of 5.5 percent energy penalty is used, EPA[2] estimates that the total electricity used by flue gas desulfurization systems in 1980 will be about 1 percent of the total electricity projected to be used during that year. Industry reports point out, however, that power companies do not have sufficient reserve capacities to supply this power. Since the Federal Power Commission requires that reserves of the order of 20 percent of

the expected peak loads are necessary to avoid sporadic power curtailments, the installation of FDS may be delayed.

Low Btu Gasification

Another promising method for utilizing low sulfur fuels is the production of low BTU gas from coal. There are two advantages of this approach to the problem: First, the gas is produced under reducing conditions with the result that sulfur is converted into $H_2S$. This is an advantage because $H_2S$ can be readily removed with existing technology at least at low temperatures. It should be noted, however, that the conventional processes for $H_2S$ removal have the disadvantage of necessitating the gas to be cooled prior to treatment. This results in a considerable loss of heat and a lowering of the efficiency. This problem can be eased by the design of efficient head transfer and recovery systems. The gas can also be generated at high pressures. This is advantageous because there is the possibility of using more advanced power cycles to generate power in new power installations.

It should be recognized that the production of low BTU gas is not a new technology. Long before the discovery and the ability to have long-range transmission of large volumes of natural gas, there were a number of local town gas facilities which produced a low BTU gas. In many parts of Europe this is still the case. So that the technology to produce low BTU gas exists. But, its application to supplying a power plant with a varying load has not been demonstrated. Low BTU gases are generally acceptable fuels

for gas, steam, turbine power cycles and should be adequate for conventional power plants, although studies are needed to determine the lower acceptable limits in the heating value with regards to combustion characteristics and reduction of boiler ratings.[15]

Coal gasifiers can be divided into two principle configurations.[11,12] These are processes in which the fuel is maintained in a fixed bed and where the fuel is suspended in a gas. Suspension processes are further categorized into fully entrained, fluidized bed, and cyclone or vortex gasifier systems.

The gas and solid flow may be countercurrent or concurrent in the fixed bed processes. Countercurrent processes have found more industrial usage. In the suspension processes the particles may move with the gas, as in full entrainment; or they may move relative to it, which happens in vortex, cyclone and fluidized bed systems.

Counter-current gasifiers have a down flow of coal and an upflow of gas, and generaly have high thermal efficiencies and good flexibility. They have, however, low gasification rates, small capacities, and excessive tar formation. Co-current gasifiers either up or down flow, have higher gasification rates and minimal tar formation because of higher temperatures but thermal efficiency is lower unless energy recovery is effected or the synthesis gas is cleaned and used at a high temperature. Fluidized bed properties are intermediate. Fluidized bed reactors can be made in large sizes but the operating range is small. Process modifications such as recycle and waste heat

recovery, can provide improvements. Examples of the fixed bed process and the three suspended processes are: The Lurgi, the Kopper-Totzek (entrained bed) the Winkler (fluidized bed) and the Ruhrgas gasifiers (vortex bed), respectively. The status of a number of typical low BTU gasification systems is given in Table 2.

An example of a more advanced power design that can be used for high pressure low BTU gasification is the combined cycle power plant.[13, 14, 15] In this configuration, the gas is expanded from a high pressure to a low pressure through a turbine-generator configuration which generates electricity. The gas is then burned to produce steam in a conventional boiler. Steam from the boiler is then used to operate steam turbines which when coupled to generators produce electrical output. The combination of the electricity generated from the gas turbine and steam turbine generator outputs gives rise to an increased overall plant efficiency.

There are, however, some disadvantages in operating a low BTU gasification installation. The disadvantages are

1. Its operation is more like chemical plant than a power plant.
2. It requires a high degree of control of flow of composition of most of the process streams.
3. It is more difficult to start up and shut down.
4. It requires more time to reach optimum conditions than an ordinary power plant.

As a result, special training of personnel and the possible additon of manpower with different skills, that is chemical plant experience, might be needed. This latter

factor of increased personnel requriements may make a low BTU gasification system too costly for small installations, but could possibly have great advantage in the case of large installations. Another problem is the need to start up and shut down the gasification facilities simultaneously with the power plant. This assumes, of course, that large scale storage of the low BTU gas is impractical. Because start ups and shut downs are known to cause difficulties in the chemical industry, it might not be desirable for utilizing low BTU gasifiers for peak operations. Rather, they should be used in plants that have a steady demand factor.

As noted above, it is necessary to operate the gasifier under pressure in a combined cycle configuration. Not only does this produce a more efficient power plant, but it also simplifies the design of the gasification process itself. It should be noted, however, that because of the problems in feeding coal through a system under pressure, only one high pressure process, the Lurgi process, has been commercialized. It currently has fourteen plants now operating around the world and is in the process of expanding its operation to a number of additional installations.

It is of interest to point out a few of the more important limitations of the Lurgi process. These limitations include[15]

1. The coal has to be carefully sized,
2. The process has difficulties in utilizing caking coals, and
3. The process is limited in terms of capacity.

The largest reactor vessel that has been built is only about 12 - 13 feet in diameter which makes it necessary to install multiple units for a plant designed to produce a large amount of gas. While it is recognized that a larger vessel would be desirable, one has not been built, at least not to date.

Although Lurgi is the only pressurized process available for immediate workable application, a number of new processes are in the development stage, with several more at the research and conceptual stage. Preliminary design and economic evaluation should make it possible for further development. It appears that given sufficient time for development, other processes will become economically superior to Lurgi.

Waste Disposal

The waste disposal problems associated with low BTU gasification processes do not appear to be materially different from those of coal fired units. The ash which is formed is comparable to flyash with regard to its pollution potential. The hydrogen sulfide is converted to elemental sulfur which is the best by-product from an environmental point of view.

Space Requirements

The space requirements for low BTU installations are not trivial. The sole advantage of the gasification system is that it can be constructed a short distance away from the power plant. This allows a certain flexibility

in siting the installation. This area should be the subject of a detailed investigation.

## Time Requirements for Installation

The time requirements for installation of a low BTU gasification system are comparable to those for stack gas scrubber systems.

## Tie-In Requirements

The tie-in requirements for a low BTU gasification system are comparable to those for stack gas scrubber systems.

## Institutional Barriers

The institutional barriers which were listed for stack gas scrubbing are generally applicable to low BTU gasification. The only major difference is in the genesis of the control strategy.

## Energy Requirements for Low BTU Gasification Systems

The thermal efficiency for producing low BTU gas is estimated to range from 70 to 80 percent.[14, 15, 17] Electric power generation efficiencies for conventional power plants are approximately 38 to 40 percent.[15] Combined gas, steam, turbine systems have potential for overall plant efficiencies of up to 47 percent when high temperature gas turbines are developed.[13, 14] The realization of these

higher overall plant efficiencies in the future is not only attractive economically but necessary if our coal reserves are to be utilized in a more efficient manner.

Comparison of Stack Gas Cleanup Systems with Low BTU Gasification Systems

It was noted in an earlier section that over 99 utilities have committed themselves in varying degrees to the installation of $SO_2$ stack gas cleanup devices. Eighty-two percent of these installations, amounting to approximately 29,000 mw are currently committed to lime or limestone based processes. The remaining applications are distributed more or less equally among the other processes; i.e. magnesium oxide, sodium hydroxide and catalytic oxidation systems. This suggests that the most advanced process, at least from the view point of industry, is the lime or limestone scrubber system.

In reviewing the low BTU gasification installation, it was found that the major processes which have been operated commercially around the world are the Lurgi, Koppers-Totzek, and the Winkler processes. When low BTU gasification processes are considered for integration into a power generation as the sole source of gas, the Lurgi process is the only one which is considered commercial. If a compressor-turbine set is added to the low BTU gasifier to form a combined cycle configuration, then Lurgi is the only gasifier that is under test at this time at the pilot scale level.

In comparing the relative merits of stack gas scrubbing to low BTU gasification as a means of making high sulfur

coal available in the near term it appears that lime or limestone scrubbing units are in competition with the Lurgi gasification systems.

In assessing the technological merits of stack gas scrubbing it was found that the scrubbers use approximately 5.5% of the energy generated by the plant on which they are installed.[2] For lime or limestone systems, approximately 3 tons/mw day of sludge is generated on a dry basis or 8 ton/mw day on a wet basis which must be disposed of in some manner.[5] For regenerative systems, a by-product is produced, usually sulfur, which can be stored or sold. Based on current and any foreseeable possible technologies there is no possibility that a stack gas scrubber system can ever be anything but an energy drain on the system it controls. In this sense it is a deadend technology. Further, the waste disposal problems associated with throw-away processes are immense.

By way of contrast, the low BTU gasification combined-cycle system properly integrated into a conventional power generation system has tremendous possibilities for technological improvement. The primary technological advances that must be made in order to fully realize the potential of the low BTU gasification system is a higher allowable inlet gas temperature to the compressor, higher particulate removal efficiencies in collection devices upstream of the turbine and an $H_2S$ removal system capable of operating at high temperatures. This configuration has the potential to increase the overall system efficiencies of conventional power plants from 38% to 47%.[13, 14] In addi-

tion, the probability that these technological improvements will occur is high. For example, Pratt Whitney, a major manufacturer of turbines, has reported that aircraft turbines now cruise with inlet temperatures around $2000^{o}F$.[14] It is projected that attainable inlet temperatures could reach $2800^{o}F$ during the next decade. Inlet temperatures of $2400^{o}F$ could result in an overall plant efficiency of almost 44%.[14] In additon, the current $H_2S$ cleanup processes for gasification require that the temperature of the process stream be lowered considerably in order to use present day abatement technologies. Subsequent technological development of processes which can remove $H_2S$ at high temperature could result in a further increased efficiency of the gasification system. Again, there is every reason to believe that these advances will occur. This would further increase the potential overall efficiencies of power generation configuration. In low BTU gasification systems, elemental sulfur is the major by-product. As with the stack gas cleanup systems, this by-product can be either stored or sold. The amount of ash generated from these processes is approximately the same as that generated by conventional coal burning installations.

In comparing the two technologies discussed above, it is seen that in terms of energy efficiencies, the stack gas cleanup method is a deadend technology whereas the low BTU gasification option provides tremendous potential for increased energy efficiencies. For this reason, the most attractive long term technological alternative is low BTU-combined cycle gasification.

Current estimates of capital costs for retrofit stack gas cleanup range from $45 to $108 per kw.[2,3,5] The reported

capital costs for low BTU gasification retrofit configurations range from \$110/kw to \$498/kw.[14,15,16,18] These costs are for using these two technologies on conventional power generation systems. For new plant installations, however, IGT[14] reports costs of \$280/kw for an integrated power system which includes a low BTU gasifier operating in a combined cycle configuration. This compares with the \$300/kw which is often quoted for conventional coal burning installations without provisions for stack gas cleanup if high sulfur fuels are used.[15] These costs are summarized in Tables 3 and 4.

Because of the potential for technological improvement associated with low BTU gasification systems, it is recommended that a subsidy be created to encourage the development of gasification processes in the utility industry. The subsidy should be guaranteed for a fixed time period after which the utilities would assume full economic responsibility. The duration of the subsidy would be determined by reasonable estimations regarding the time required for realizing the technological improvements in turbine blading, high temperature $H_2S$ removal and dust removal capabilities necessary for the ultimate development of the gasification system.

Institutional considerations also play a large role in mapping out sulfur abatement strategies. The stack gas sulfur oxide removal method was the solution proposed by the regulatory agencies for utilizing high sulfur coal. The industries were less than enthusiastic regarding this solution because it represented a drain on their power generation systems and would never improve their economic

position. Low BTU gasification with a combined cycle, however, was an alternative proposed by industry and which has the potential to improve their economic position over the long term. For this reason, it seems likely that with the proper encouragement; i.e., a subsidy, there is a much higher probability of industry providing real leadership to see that this technology reaches maturity in the shortest period of time.

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Table 1

Development Status of Scrubber Process Systems

| Process Types | Concept | | Bench | | Pilot | | Demo. | | Commercial | | Fuel Type | | Efficiency or Projected Efficiency |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Const | Test | Const | Test | Const | Test | Const | Test | | | |
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | Coal | Oil | |
| Limestone Scrubbing | X | X | X | X | X | X | X | X | X | X | X | | 70 - 95 |
| Lime Scrubbing | X | X | X | X | X | X | X | X | X | X | X | | 80 - 98 |
| Sodium Hydroxide Scrub. | X | X | X | X | X | X | X | X | | | X | | 90 - 95 |
| Zinc Oxide Scrubbing | X | X | X | X | X | X | | | | | X | | |
| Magnesium Oxide Scrub. | X | X | X | X | X | X | X | X | | | | X | 90 |
| Sodium Carbonate Scrub. | X | X | X | X | X | X | X | X | X | X | X | | 80 - 90 |
| Formale Scrubbing | X | X | X | X | | | | | | | | | |
| Ammonea Scrubbing | X | X | X | X | X | X | | | | | | | |
| Sodium Citrate | X | X | X | X | X | X | | | | | | | |
| Calsox | X | X | | | | | | | | | | | |
| Mosox | X | X | | | | | | | | | | | |
| Catalytic Oxidation | X | X | X | X | X | X | X | X | | | X | | |
| Activated Carbon Sorp. | X | X | X | X | X | X | | | | | | | |
| Manganese Oxide Sorp. | X | X | X | X | X | X | | | | | | | |

Table 1 (Continued)

Development Status of Scrubber Process Systems

| Process Types | Concept | | Bench | | Pilot | | Demo. | | Commercial | | Fuel Type | | Efficiency or Projected Efficiency |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Const | Test | Const | Test | Const | Test | Const | Test | | | |
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | Coal | Oil | |
| Alkalized Alumina Sorp. | X | X | X | X | X | X | | | | | | | |
| Reinluft-Char. Sorption | X | X | X | X | X | X | | | | | | | |
| Lignite Ash Sorption | X | X | X | X | X | X | | | | | | | |
| Mixed Metal Oxides Sorp. | X | X | X | X | X | X | | | | | | | |
| Molten Salts | X | X | X | X | | | | | | | | | |
| Moltan Carbonate | X | X | X | X | | | | | | | | | |
| Fluidized Bed | X | X | X | X | X | X | | | | | | | |
| | | | | | | | | | | | | | |
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Table 2

Status of Typical Low BTU Gasification Processes

| | Concept | | Bench | | Pilot | | Demo. | | Commercial | | Coal Condition | | HHV* | Type Reactor | | | Operations Pressure | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Const. | Test | Const. | Test | Const. | Test | Const. | Test | Caking | Non-Cak. | | Fluid.Bed | Entrained Bed | Moving Bed | 0-15 psig | 100-500 psig | 1000-1500 psig |
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | Yes | No | | | | | | | |
| Atgas | X | X | X | X | | | | | | | X | X | 100-200 300-500 | Molten-iron bath | | | X | | |
| Bi-Gas | X | X | X | X | X | | | | | | X | X | 100-200 300-500 | | X | | | | X |
| Hydrane | X | X | X | X | | | | | | | X | X | 300-500 | X | | | | | X |
| $CO_2$ Acceptor | X | X | X | X | X | X | | | | | X | X | 300-500 | X | | | | X | |
| Koppers Totzek | X | X | X | X | X | X | X | X | X | X | X | X | 300-500 | | X | | X | | |
| Lurgi | X | X | X | X | X | X | X | X | X | X | | X | 100-200 300-500 | | | X | | X | |

*HHV is the higher heating value (Btu/scf).

Table 2 (Continued)

Status of Typical Low BTU Gasification Processes

| | Concept | | Bench | | Pilot | | Demo. | | Commercial | | Coal Condition | | HHV | Type Reactor | | | Operations Pressure | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Const. | Test | Const. | Test | Const. | Test | Const. | Test | Caking Yes | Non-Cak. No | | Fluid. Bed | Entrained Bed | Moving Bed | 0-15 psig | 100-500 psig | 1000-1500 psig |
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | | | | | | | | | |
| Molten Salt | X | X | X | X | | | | | | | X | X | 300-500 | Molten-salt Bath | | | | | X |
| Synthare | X | X | X | X | X | | | | | | X | X | 100-200<br>300-500 | X | | | | | X |
| U-Gas | X | X | X | X | X | X | | | | | X | X | 100-200 | X | | | | X | |
| Union Carbide | X | X | X | X | X | | | | | | X | X | 300-500 | X | | | | X | |
| Wellman Galusha | X | X | X | X | X | X | X | X | X | X | X | X | 100-200<br>300-500 | | | X | X | | |
| Westinghouse | X | X | X | X | X | | | | | | | | 100-200 | X | | | | X | |
| Winkler | X | X | X | X | X | X | X | X | X | X | X | X | 100-200<br>300-500 | X | | | X | | |

Table 3

Comparison Between the Capital Cost of Retrofitting a Coal Gasifier to an Existing Boiler and Stack Gas Cleanup

| Process | | Cost |
|---|---|---|
| EPRI[18] | | $339-495/kw |
| IGT U-GAS[14] | | $110/kw |
| Federal Power Commission Report[16] | | $148/kw |
| BCR Air Blown Two-Stage Gasifier[15] | | $117/kw |
| Stack Gas Clean-up - | Retrofit[3] | $45-65/kw |
| | Retrofit[5] | $65-100/kw |
| | Retrofit[2] | $50-108/kw |
| | Retrofit[18] | $51-91/kw |

Table 4

Comparison Between the Capital Cost of a New Low BTU - Combined Cycle to a New Coal Fired Conventional Boiler

| Process | Cost |
|---|---|
| Low BTU-Combined Cycle[14] | $216-268/kw |
| New Conventional Boiler[15] | $300/kw |

# SECTION VI: MEDIUM BTU COAL GASIFICATION

## A. Introduction

Virtually all low Btu coal gasification processes can be adapted to produce a medium Btu gas. The advantage of this quality gas is its siting flexibility and its adaptability to the existing boiler sizes and characteristics used by industrial and commercial complexes. Additionally, because the generation can be relatively small scale and can produce both electricity and process steam, both electric utilities and consumers can be freed of their interdependence. Given the projected demand for electricity, and the problems foreseen in supplying this demand solely by expansion of the utility industry, consumer generation of their own electricity, in whole or in part, may be an important national priority.

The particular system discussed here has been developed by Professor S. L. Soo at the University of Illinois at Urbana-Champaign. While it has been designed for relatively small scale operations (industrial/commerical size) and does not require oxygen in the process (making it safe), the conclusions are believed to be valid for medium Btu coal gasification in general.

The use of coal has been declining relative to other fuels in almost every area of fuel consumption. Part of the problem is transportation, part of the problem is air pollution control, and part of the problem is that coal in its natural form is clearly the least flexible of all fossil fuels. Because it is solid and contains substantial amounts of waste, coal involves greater difficulty at every stage of the use

process. It is more difficult to extract, transport and handle in consumption than either oil or gas. Furthermore, after combustion, an ash residue remains that creates a disposal problem. As a result, coal is used in its natural form only when it is cheaper than other fuels. Moreover, in its natural form the economies of scale in coal handling are such that only large users find that they can cheaply overcome the cost disadvantages. This fact largely explains the concentration of coal use among large consumers of fuel.

Increasingly, industrial, commercial and government establishments have restricted their use of coal. It has long been a desire of the coal industry to overcome these drawbacks by developing economically viable techniques for manufacturing synthetic oil and gas from coal. It has also been argued that the impending exhaustion of domestic conventional oil and gas supplies would make the need for such synthesis inevitable.

The coal gasification proposal (contained in Appendix H) is a plan to design, construct, and operate a coal gasification plant which would use high sulfur Illinois coal to supply the University of Illinois' Abbott Power Plant. This plant would use 500-600 tons of coal per day to produce a medium Btu gas. For most industrial firms and institutions, generating either electricity, heat or both, the gasification facility constitutes a demonstration plant. For large systems, such as an electric utility, it may serve as a pilot plant.

Successful demonstration of a coal gasification plant implies that others will follow its use. This also implies greater use of coal, particularly high sulfur coal. Among the major potential users of a medium Btu gasification plant are industrial, commercial, and government complexes. Table VI-1 indicates the use of coal by manufacturing industries.

Table VI-1

Reported Coal Consumption and
Net Electric Power Production
by Manufacturing Industries, 1967

| | Thousands of Tons of Coal a/ | Million Kilowatt Hours Generated b/ |
|---|---|---|
| Food and Kindred Products | 5,889.2 | 2,191.1 |
| Tobacco | 348.6 | 112.9 |
| Textile Mill Products | 1,810.7 | 498.8 |
| Lumber and Wood | 253.8 | 621.7 |
| Furniture and Fixtures | 198.1 | 46.4 |
| Paper and Allied Products | 12,839.7 | 22,987.1 |
| Printing and Publishing | 32.6 | 6.9 |
| Chemicals and Allied Products | 19,652.8 | 21,372.7 |
| Petroleum and Coal Products | 865.6 | 4,088.7 |
| Rubber and Plastic Products | 1,882.6 | 582.3 |
| Stone, Clay and Glass | 11,211.2 | 1,193.1 |
| Primary Metal Industries | 7,700.5 | 22,526.7 |
| Fabricated Metal Products | 1,036.4 | 43.5 |
| Machinery, Except Electrical | 1,323.0 | 495.4 |
| Electrical Equipment and Supplies | 806.8 | 187.6 |
| Transportation Equipment | 3,194.5 | 2.0 |
| Instruments and Related Products | | 576.0 |
| Miscellaneous | | 1.5 |
| Totals | 69,045.8 | 77,534.4 |

---

Source: U.S. Census.

a/ The data here are compiled from surveys of users and are incomplete because the Census by law cannot release data that provides information about individual firms.

b/ From all sources.

The data in Table VI-1 suggests that many industrial users employ coal to generate electricity. This may be indirectly inferred from the association between high levels of coal use and substantial electric power output. This electricity is probably jointly produced with process steam. Where both process steam and electricity are needed, it is often most efficient to generate steam in modern boilers at higher temperatures and pressures than are desired for process use alone and to pass the steam through a turbine producing both electricity and steam of the necessary characteristics. Presumably these uses are subject to the same air pollution challenges as those facing electric utilities. It is, however, these industries which are prime candidates for the demonstration effect of medium Btu coal gasification.

Because of the characteristics of the proposed gasification plant, there is no reason not to use high sulfur run-of-the-mine coal. Table VI-2 shows, with respect to household and commercial, as well as industrial, sales and consumption of coal the loss of coal in terms of share of the market. This is apparent by moving from the 38.7 percent for household and commercial consumption in 1947 to the 4.61 percent in 1966. Similarly for industrial use, coal as a percent of all fuels used in this category was 55.39 percent in 1947 but was only 31.67 percent of all fuels consumed by the industrial group in 1966. Following the Clean Air Act in 1967, the decline has been even faster.

While desulfurization is often thought of in terms of stack gas scrubbing alone, it also takes place when coal is gasified. Coal may be gasified into a high Btu gas which is substitutable for pipeline quality natural gas, to a medium Btu gas which can be pipelined short distances to an industrial or utility consumer, or to a low Btu gas which must be

Table VI-2

U.S. Consumption of Coal: Household-Commercial and Industrial Consumers
1947 - 1966

| | Household & Commercial | | Industrial | |
|---|---|---|---|---|
| Year | $10^{12}$ Btu | Percent of all Fuels | $10^{12}$ Btu | Percent of all Fuels |
| 1966 | 573.0 | 4.61 | 5806.0 | 31.67 |
| 1965 | 546.0 | 4.60 | 5640.0 | 32.14 |
| 1964 | 560.0 | 5.02 | 5362.0 | 31.56 |
| 1963 | 671.0 | 6.07 | 5014.6 | 31.66 |
| 1962 | 798.6 | 7.26 | 4761.6 | 31.78 |
| 1961 | 782.9 | 7.52 | 4693.7 | 41.00 |
| 1959 | 814.9 | 8.36 | 4691.8 | 33.77 |
| 1957 | 981.3 | 11.26 | 5792.4 | 40.07 |
| 1955 | 1443.7 | 16.74 | 5976.1 | 43.14 |
| 1953 | 1614.8 | 20.82 | 6056.9 | 44.86 |
| 1950 | 2252.5 | 29.67 | 5830.4 | 48.01 |
| 1947 | 2585.5 | 38.17 | 7013.6 | 55.39 |

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Source: Department of Health, Education and Welfare, Control Techniques for Sulfur Oxide Air Pollutants, January 1969, Table 4-1, p. 4-3.

used in the proximity of the gasification plant and is limited primarily to electric power generation. In all of these processes, sulfur is removed and the product can meet EPA standards.

If desulfurization problems are overcome then, in addition to supplementing and/or reducing the need for nuclear power generation, the use of coal for electric power, industrial process heat and institutional uses would free scarce petroleum and natural gas for application to home heating, light industry and commerce, and transport (i.e., an effective increase in the supply of those fuels where fuel substitution is low.

Because the proposed plant produces a medium Btu gas, there are some special advantages. First, the gas can be piped about 25 miles. This demonstrates siting flexibility to future users. Second, the water use is low. This means that siting can be accomplished almost anywhere. Third, it is clean. The hydrogen sulfide is turned into sulfur; therefore the disposal problem is small.

Other advantages accrue to this particular type of medium Btu coal gasification plant. First, it does not use pure oxygen in the gasification process. Therefore, construction and operating costs are lower than other processes. The use of much auxiliary equipment is eliminated. It is also much safer. Second, because of the indirect heating, there are clean stacks and no air pollution problems. Third, the plant is designed to accomodate varying qualities of coal supply. And fourth, with add-ons, the plant can be made to utilize solid waste, thereby lessening disposal and land fill problems for some cities and towns.

## B. Medium Btu Gasification Process Analysis and Costs

The gasification process converts a mixture of steam and coal to hydrogen, carbon monoxide, and carbon dioxide. Steam for the gasification process is produced and heated by burning part of the gas generated. In the process, sulfur in the coal is converted by the steam to hydrogen sulfide and can be removed. The gas produced for the process boiler and for piping into power plant boilers is virtually sulfur-free, medium Btu gas.

The coal used in this process can be run-of-the-mine. The gas burned in the plant will cause no significant pollution and will permit more efficient boiler operation at lower stack gas temperatures.

The basic chemical reactions are:

1. $C + H_2O \rightleftarrows CO + H_2$ (41.91 kcal/g-mole)

2. $\begin{cases} C + 2H_2O \rightleftarrows CO_2 + 2H_2 & \text{(42.60 kcal/g-mole)} \\ CO + H_2O \rightleftarrows H_2 + CO_2 & \text{( .69 kcal/g-mole)} \end{cases}$

The coal is not burned; neither air nor oxygen are required as the process uses steam as both a reactant and heat transfer medium. The high pressure condensation of the steam at the end of the process removes $H_2S$, $SO_2$ and $CO_2$ due to their high soluability. The predominancy of reaction (1) or reaction (2) depends on the quenching temperature. Carbon dioxide ($CO_2$) formed simultaneously will be removed by absorption. The numerals indicate the heat to be furnished for gasification.

Typical operating parameters are as follows:

| | |
|---|---|
| Coal Consumed | 550 tons/day |
| Water | |
| Converted (consumed) | 120 gal/min. |
| Cycled (needs treatment) | 620 gal/min. |
| For Cooling (recycled) | 10,000 gal/min. |
| Air | 52,000 cu.ft/min. |
| Product Gas | |
| At low temperature & pressure | 15,400 cu.ft/min. |
| At high temperature & pressure | 22,100 cu.ft/min. |

The cost comparisons in Table VI-3 are based only on the production of steam. They exclude any production of electricity. It will be seen that coal gasification compares favorably with either an oil fired (No. 2 oil) or conventional coal fired plant.

A low temperature, low pressure operation gasification facility of 58 percent efficiency would require 170,000 tons of coal annually. However, because of the character of the gasification process, the coal could be low cost and run-of-the-mine. The price per ton could reach $23.94 before equalling the annual cost of No. 2 oil. This low temperature, low pressure process has been demonstrated and an efficiency estimate of 58 percent is quite conservative.

The high temperature, high pressure operation is less certain. If the potential 83 percent efficiency can be achieved, only 120,000 tons of coal would be required. In order to equal the annual cost of No. 2 oil, high sulfur, run-of-the-mine Illinois coal would have to rise to nearly $34 per ton.

One of the major considerations for capital projects is the length of time to recover the initial outlay: the payout period. One method of recovering the outlay is through

Table VI-3

Fuel Costs - Various Alternatives
To Produce 2.1 Billion Pounds of Steam - Projected FY-75 Usage

| | | Relative Cost |
|---|---|---|
| All Oil Fired - 18,500,000 Gallons Per Year | | |
| At $.22 per gallon | $4,070,000 | 1.00 |
| At $.30 per gallon | $5,550,000 | 1.36 |
| At $.35 per gallon | $6,475,000 | 1.59 |
| Conventional Coal Fired - 125,000 Tons Per Year (Stoker coal-cleaned & screened) | | |
| At $20 per ton* (high-sulfur Illinois coal) | $2,500,000 | 0.61 |
| At $30 per ton* (high-sulfur Illinois coal) | $3,750,000 | 0.92 |
| At $40 per ton (low-sulfur western coal, delivered) | $5,000,000 | 1.22 |
| Coal Gasification | | |
| Low Temperature & Pressure - 170,000 Tons Per Year | | |
| At $10 per ton (run-of-the-mine) | $1,700,000 | 0.42 |
| At $20 per ton (run-of-the-mine) | $3,400,000 | 0.84 |
| At $23.94 per ton (parity with $.22 oil) | $4,070,000 | 1.00 |
| High Temperature & Pressure - 120,000 Tons Per Year | | |
| At $10 per ton (run-of-the-mine) | $1,200,000 | 0.29 |
| At $20 per ton (run-of-the-mine) | $2,400,000 | 0.58 |
| At $33.92 per ton (parity with $.22 oil) | $4,070,000 | 1.00 |

--------------------

*These cost estimates do not include the installation and operating costs of a stack gas scrubber which would be necessary to burn high-sulfur coal.

reduced fuel costs. Assuming that the plant requires 2.1 MMBtu to produce the required amount of steam annually, heat produced by burning No. 2 fuel oil at $.22 per gallon costs $1.937 per MMBtu. Heat produced by burning gasified coal costs $.873 per MMBtu for the low temperature process or $.611 per MMBtu for the high temperature process.

The annual cost differential between oil and the two gasification processes are the product of the difference in cost per MMBtu and the number of MMBtu required. The payout period represents the number of years of this differential necessary to recover an initial investment of $10 million. For the low temperature gasification process, this is 4.5 years; for the high temperature process, it is 3.6 years. (Table VI-4)

Table VI-4

Payout Period Through Fuel Savings

| | |
|---|---|
| Cost of producing one million Btu (MBtu) by burning oil (82% efficiency, $.22 per gallon, 138,500 Btu/gallon). | $1.937 |
| Cost of producing one MBtu by gasification of high-sulfur coal, low temperature and pressure (52.2% efficiency, $10.94 per ton, 24 MBtu per ton). | $.873 |
| Cost of producing one MBtu by gasification of high-sulfur coal, high temperature and pressure (74.7% efficiency, $10.94 per ton, 24 MBtu per ton). | $.611 |
| Annual Cost Differentials | |
| Oil vs. low-temperature gasification | $2,234,400 |
| Payout period to recover $10 million | 4.5 years |
| Oil vs. high-temperature gasification | $2,784,600 |
| Payout period to recover $10 million | 3.6 years |

## C. Impact on the State of Illinois

The State of Illinois contains over 19 percent of the reserves of bituminous coal in the United States. It has by far the largest reserves of bituminous coal of any state in the United States. Nevertheless, in 1970, Illinois continued to rank as only the fourth largest coal producing state in the Union. The discrepancy between its reserve position and its production position can be attributed to the fact that most of the bituminous coal in the State of Illinois is high sulfur. In one publication it is wryly pointed out that, "By relatively low sulfur coal, the writers refer to coal that appears to be of the order of 2.5 percent sulfur or less, which is significantly less than the normal range of 3 to 5 percent."[(1)]

Two evaluations of sulfur reduction in Illinois coals have been made by the Illinois State Geological Survey. Both are pessimistic. In the first, a total of 37 samples taken from 32 mines were evaluated. The conclusion was, "The Illinois coals studied for this report indicate that only a few could be prepared with a sulfur content of 1.5 percent or less. These few coals had 2 percent or less of sulfur in the raw coal samples.

Approximately 50 percent of the sulfur in the average Illinois coal is in pyritic form, and about half of this pyritic sulfur can be removed with a reasonable amount of reject. This is equivalent to a reduction of one-fourth of the total sulfur content."[(2)]

The second study was based on 28 samples from 22 mines. It reached the conclusion that:[(3)]

1. In only a small portion of Illinois coals can sulfur be reduced by gravity separation methods to 1.5 percent or less. These coals are all relatively low in sulfur as mined.

2. The percentage of reduction of the sulfur with many Illinois coals is high, even with only a moderate quantity of reject. The maximum reduction of total sulfur in cleaned coal reported in this study with 80 percent recovery was 65 percent, and the average reduction was 38 percent. Expressed in percentage figures, the maximum reduction in sulfur was nearly 4 (from 7.70% to 3.88%) and the average reduction in sulfur was slightly more than 1.5 (from 4.11% to 2.52%).

Unless new forms for the utilization of Illinois coal are found the future appears bleak. Energy demands in PAD District II, which includes Illinois, are anticipated to grow by 32.9 percent from 1970 to 1975, by 59 percent by 1980 and by 90.5 percent by 1985.(4) Table VI-5 shows the projected demand for coal in PAD District II through 1985. Two features must be noted. First, between 1970 and 1975 the increased demand for coal will be only 31.6 percent, to 1980 it will be 44.7 percent and by 1985 it will have increased only 51.4 percent. Second, all of this increase takes place in only one sector--that of electric utilities. There is room for major increases in coal usage, if it is gasified, in the industrial and commercial sectors. With respect to Illinois coal in particular it is probable that, given its relatively high sulfur content, it will not share in even the modest gains forecast for PAD District II.

Between 1966 and 1970, there appeared to be a leveling off of the sales of coal in the State of Illinois to electric utilities. The 1970 figure is, however, fifty percent higher than that for 1957. With respect to coke and gas plants, sales have been level and at approximately the same rate as

Table VI-5

Coal Demand Projection by Major Consuming
Sector, PAD District II, Selected Years
(million tons per year)

| | 1970 | 1975 | 1980 | 1985 |
|---|---|---|---|---|
| Residential/Commercial | 10.9 | 7.0 | 6.4 | 2.1 |
| Industrial | 50.0 | 55.0 | 55.0 | 55.0 |
| Transportation | - | - | - | - |
| Electric Utility | 177.3 | 252.2 | 284.5 | 304.9 |
| Non-Energy | 3.4 | 3.7 | 3.7 | 3.7 |
| Totals | 241.6 | 317.9 | 349.6 | 365.7 |

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Source: M. Rieber and R. Halcrow, U.S. Energy and Fuel Demand to 1985: A Composite Projection by User Within PAD Districts, University of Illinois at Urbana-Champaign, Center for Advanced Computation, CAC Document No. 108R, Revised May 1974, Table 1, pp. 3-7.

that in 1957. Sales to the industrial sector also have been steadily downward and are approximately one-half the 1957 level.[5] The figures clearly show the value of the demonstration plant for coal gasification in terms of potential increases in sales to the commercial and the industrial sectors in an effort to reclaim lost markets.

Table VI-6 presents some statistics of the Illinois coal industry from 1965 through 1973 compiled by the Illinois State Geological Survey. As a starting date 1965 was chosen because it predates both the air pollution control standards and the new mine safety and health laws. Contrary to economic expectations, in the face of steadily increasing coal prices, the number of mines, both strip and underground, have steadily declined. Employment has been rising but there is reason to believe that this is associated with two factors: the first is the increased number of personnel working above ground in the area of coal preparation due to air pollution control regulations; the second has to do with the increased number of miners needed to offset reduced coal productivity resulting from the mine health and safety laws. If output increased, clearly more men and women would be employed in the mines both above and below ground. There would be large regional employment effects especially downstate. The value of gasification in this respect is that it utilizes any Illinois coal, therefore, the employment effects would be spread evenly over all kinds of mines in the Illinois coal mining regions.

In 1973 the Illinois State Chamber of Commerce made a study of the impacts of pollution control regulations on some Illinois industries.[6] Interestingly enough, the Chamber of Commerce did not specifically cover coal as one of the industries affected. The eight industries studied, which included

Table VI-6

Illinois Coal Industry

| | No. of Mines | Employees | Production (tons) | Average Value/ton (all coal) |
|---|---|---|---|---|
| | | | **1973** | |
| | U 24 | U 7,794 | U 32,577,353 | |
| | S 32 | S 3,615 | S 28,971,317 | N.A. |
| Total | 56 | 11,409 | 61,548,670 | |
| | | | **1972** | |
| | U 26 | U 7,870 | U 31,715,795 | |
| | S 33 | S 3,367 | S 33,805,599 | $6.14 |
| Total | 59 | 11,237 | 65,521,394 | |
| | | | **1971** | |
| | U 27 | U 7,088 | U 29,453,926 | |
| | S 36 | S 3,483 | S 28,961,313 | $5.46 |
| Total | 63 | 10,571 | 58,415,239 | |
| | | | **1970** | |
| | U 29 | U 6,785 | U 31,615,570 | |
| | S 35 | S 3,429 | S 33,268,533 | |
| Total | 64 | 10,214 | 64,884,103 | $4.92 |

Continued

Table VI-6 Continued

| | | | | |
|---|---|---|---|---|
| | | **1969** | | |
| | U 28 | U 5,944 | U 30,172,627 | |
| | S 34 | S 3,647 | S 34,659,957 | |
| Total | 62 | 9,591 | 64,832,584 | $4.32 |
| | | **1968** | | |
| | U 36 | U 6,028 | U 26,084,430 | |
| | S 33 | S 3,510 | S 36,058,646 | $4.01 |
| Total | 69 | 9,538 | 62,143,076 | |
| | | **1967** | | |
| | U 33 | U 5,392 | U 27,650,000 | |
| | S 44 | S 3,413 | S 37,164,771 | $3.88 |
| Total | 77 | 8,805 | 64,814,771 | |
| | | **1966** | | |
| | U 36 | U 5,566 | U 27,132,171 | |
| | S 48 | S 3,428 | S 36,080,526 | $3.85 |
| Total | 84 | 8,994 | 63,212,697 | |
| | | **1965** | | |
| | U 43 | U 5,470 | U 25,571,442 | |
| | S 54 | S 3,320 | S 32,661,038 | $3.74 |
| Total | 97 | 8,790 | 58,232,480 | |

U - Underground
S - Strip

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Source: Ms. Portia Smith, Illinois State Geological Survey, Compilation, July 1974.

approximately 750 plants and 160,000 employees or about 12 percent of the industrial employment included: fruit and vegetable canning and freezing; the iron and steel foundry industry; industrial chemicals; non-ferrous metals; electric power generation; blast furnace and basic steel; petroleum refining; and the farm machinery, automotive, and aircraft industry. Those industries primarily affected were the industrial chemical industry, the non-ferrous metals industry, the blast furnace and the basic steel industry, the petroleum refining industry, and the farm machinery, automotive, and aircraft industry. Of these last coal, by way of the gasification process, can make inroads in all but blast furnaces and basic steel which require metallurgical grade coal and petroleum refining which uses its own internally generated fuel. The impacts of the air pollution control regulations and their solutions are seen in terms of lost investment, tax revenues and employment. While the State suffers in general from these impacts, local impact problems are relatively much greater.

The Commission estimated that 8,500 coal production employees were affected by air pollution control regulations and that State revenue losses in the coal mining sector could be calculated at approximately $110 million per year in 1973 dollars.(7) An additional 950 employees are affected in the iron and steel foundry industry with 400 more employees affected in the fruit and vegetable canning and freezing industry.(8)

It must be noted that the Commission's estimates are the minimum. They are only those employees who are currently affected. The estimates do not include job opportunities foregone because coal mining will not increase as much as it might and because industries which cannot find gas will be

forced to make other adjustments which will also affect employment.

Finally, the Commission indicated that the costs in Illinois for air and water pollution abatement between 1971 and 1980 will be approximately $5 billion or $500 million per year. Of this, approximately $300 million per year will be for air pollution control alone.[9]

If State revenue losses are added to air pollution control costs it can be seen that the utilization of coal by way of gasification is a relatively cheap alternative.

The minimum return on a State investment in even the small gasification facility discussed above may be seen by examining the tax system in Illinois. According to the Department of Revenue, a retailer's occupation tax on the value of the coal accrues to sales to customers within Illinois, unless specifically exempt.

Since 1966 (prior to air pollution control regulation but after the inroads of oil and natural gas) the amount of coal sold within Illinois to industrial and commercial markets has declined more than 50 percent from 11 million tons to 5.2 million tons annually. If the gasification demonstration is successful, perhaps half of this market loss of 5.8 million tons can be recovered via gasification. At $10.94 per ton for high sulfur run-of-the-mine coal, this has a value of $31.7 million.

Since sales to State institutions and agencies are tax exempt, assume only half of this amount is subject to the retailer's occupation tax of 5 percent. This amounts to $794,000 per year in revenue to the State. In 12.6 years, the State will recover the initial $10 million.

## D. Publication and Utilization

The material in Section VI is based on:

S. L. Soo, A Steam Process for Coal Gasification.

S. L. Soo, Additional Note to a Steam Process for Coal Gasification.

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A patent for the process has already been applied for. The technical work in this area falls outside the purview of present NSF funding. However, the results of this work in terms of economic evaluation have been included.

Currently, funding for the construction of the facility and further demonstration work are under consideration by the Office of Coal Research (ERDA)(OCR Proposal No. U50233GA) and the administration of the State of Illinois. The trustees of the University of Illinois have already given their approval. Discussions have been held with the Institute of Gas Technology and others.

A paper by Michael Rieber, "Economic Impact on the State of Illinois of Medium Btu Coal Gasification," was presented at the Conference, Constraints on Coal Utilization, held at Southern Illinois University at Carbondale, May 19, 1975. It will be published in the conference Proceedings.

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## APPENDIX to SECTION VI

The proposed process gasifies coal by reacting it with steam at temperatures of 2,000 to 3,000°F or higher without the coal ever coming into contact with air or oxygen. Indirect heating of the steam entering the reactor is accomplished using a pebble bed heater which utilizes a recycled fraction of the gas produced for heating the bed. Stack emissions from the boiler and heater are as clean as any gas fired system. Since excess steam is used both for heating as well as for gasifying the coal, the sulfur in the coal is removed in a liquid solution. As a typical example, a 550 ton per day plant operating at a moderate pressure of 220 psi with a maximum steam temperature of 3,000°F, an estimated overall system efficiency around 70 percent is attainable for producing a net of 15,700 scfm of gas at 340 Btu/scf. If provision is made for stack gas treatment and solid waste is burned in the auxiliary boiler part of the system, the system efficiency can be raised up to 86 percent with a 25,700 scfm output.

A review of the most advanced low Btu gasification processes indicates that they are basically air blown systems which produce a gas having a higher heating value below 200 Btu/scf. In addition, many of these processes require extensive dust cleaning systems. It has been pointed out in the literature that any enrichment of low Btu gas utilizing $O_2$ results in a cost penalty of $\$0.20/10^6$ Btu as well as an energy penalty which can be as high as 10 percent of the electrical output of the utility to which gas is being supplied. Studies have also shown that low Btu gas utilization is somewhat limited with heating values below 200 Btu/scf

because of pipeline transport limitations. Gasification installation, having heating values above 300 Btu/scf, however, are able to be transported over sufficiently long distances to allow much greater siting flexibility. The disadvantages with this medium Btu gas in the past has been the requirement of $O_2$ enrichment. The process which is proposed here is able to supply a medium Btu gas (340 Btu/scf) without requiring $O_2$ enrichment. Further, there is no need for any dust control apparatus in the system. The gas leaving the gasification system is virtually dust free. Finally, the $H_2/CO$ ratio in the product gas is completely variable for the proposed process. In fact, by operating at high pressures, the shift conversion step can be bypassed if a high Btu gas is desired. The process can also be run under operating conditions in which no char is produced without the addition of oxygen.

A summary of the advantages and disadvantages for the proposed system is given below.

Advantages:

1. Since coal is never burned, the system can be designed to handle coal with ash having a low fusion point by controlling the maximum temperature in the gasifier.
2. There is no nitrogen introduced into the reactor and hence there is no need to use pure oxygen to achieve a medium Btu product gas. This condition results because steam is used both as a reactant and as a heat source in the reactor.
3. There is no inherent char formation in the system because of the amount of excess steam used in the reactor.

4. The fuel gas composition of the $CO/H_2$ ratio can be varied either in the initial design or during operation to suit subsequent process needs, such as methanation, methanol production, or hydrogenation.
5. The $H_2$ produced is saturated with water vapor which prevents embrittlement of steel.
6. When no external heat source is used in the auxiliary boiler, there is no air pollution from the process. Fine fly ash products are removed with the condensate. Only water treatment and water cooling are required.
7. This coal gasification system can incorporate solid waste efficiently. When this is done, air pollution control of the combustion products of the solid waste in the boiler might be needed.
8. For high sulfur coal, the use of excess $H_2O$ assures the formation of $H_2S$ (with the amount of COS formation being neglibible). If the $H_2S$ produced from using coal having a 5 percent sulfur content is treated to produce elemental sulfur and $H_2$, this $H_2$ can be recycled in the process to be used as part of the fuel gas. For this example, the $H_2$ produced from the sulfur process amounts to about 2 percent of the total $H_2$ in the gas.
9. The higher heating value of the fuel gas can be realizable in some applications since the fuel gas does not cause acid corrosion because sulfur is removed in the process.

10. Gas is produced with an overall system efficiency of 60 to 70 percent without $N_2$ dilution or use of pure $O_2$.
11. Coal with a low fusion temperature of ash (Illinois coal has a softening temperature between 2,250°F and 2,520°F with an average of 2,360°F) can be handled in the present system. Options of reactor configurations for the proposed process include:
    a. Fixed bed--can be designed for operation at temperatures below that of ash fusion,
    b. Fluidized bed--can be designed for temperatures below that of ash fusion (gas bubbles in the fluidized bed are not as detrimental as in gasification processes using oxygen or air where short circuited oxygen will burn with the fuel gas leaving the bed),
    c. Spouting bed--for high temperature operation with slag removal, and
    d. Cyclone entrained bed--at high temperature and slag removal.
12. Unless the tar is removed by preheating at a low temperature (930°F), the tar in the coal is reduced to CO and $H_2$.
13. The 1 percent nitrogen found in the coal is either in an adsorbed or in a combined form such as CN and hydrides. These compounds will be reduced at the reactor condition to $N_2$ gas or NO (the latter being readily removed by dissolving in the condensate).
14. A high system pressure is desirable because the power consumption to pump water is less than

that for compressing the gas produced for transmission and/or storage.

Disadvantages:

1. The $CO_2$ in the raw fuel gas needs to be removed, although the MEA $CO_2$ absorption process is commercially available. This is a problem common to most gasification processes.
2. Reactor steam injection rates five times greater than those used in current design may be required. All of this water is not consumed, however. Approximately 40 to 50 percent more water may be consumed with this process under the worst case conditions. In addition to the water injected into the reactor, cooling water is also needed.
3. The pebble or refractory heater operating at high temperature with pebbles or parts undergoing alternate heating and cooling will have similar problems as in its applications in petroleum refineries. These refractory heaters are widely used in the petroleum industry.
4. The existence of a lower heating value is a result of the hydrogen in the fuel gas. This heating value depends on the $H_2/CO$ ratio as in other gasification processes.
5. For the same transmission pressure and pressure drop over a given distance, the present fuel gas calls for a 50 percent greater pipe diameter than methane. It should be noted, however, that the medium Btu gas produced in this process is ready for methanation.

The validity of the steam process of gasification has been explored, in a preliminary way, in the studies of Jensen and of Oppelt, et al., Both of these studies used electrical heating.

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Supplementary Notes

Abstracts

Nuclear power costs are reevaluated to determine the ceiling price for coal. Low sulfur coal reserves are reestimated on a consumer rather than on an as mined basis. Coal reserve/resource estimating procedures are analyzed for their policy content. Comparative cost estimates are developed for unit trains, slurry pipelines and high pressure pneumatic pipelines. Low Btu coal gasification and stack gas scrubbing are compared for $SO_2$ removal. An analysis of medium Btu coal gasification to increase coal markets is made.

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Nuclear Power Forecasts
Low Sulfur Coal Reserves/Resources
Coal Reserve/Resource Estimation
Coal Mine Productivity
Stack Gas Scrubbing Processes
Stack Gas Scrubbing Costs
Low Btu Coal Gasification
Medium Btu Coal Gasification
Unit Train Costs
Coal Slurry Pipeline Costs
Pneumatic Pipelines

Identifiers/Open-Ended Terms

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Coal Reserves
Coal Transportation
Coal Gasification
Stack Gas Scrubbing

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